STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Company	**)**	
	)	**Docket 04-0476**
Proposed general increase in natural gas	**)**	
rates (Tariffs filed June 25, 2004)	**)**	

ILLINOIS POWER COMPANY'S INITIAL BRIEF

PUBLIC VERSION

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I. INTRODUCTION AND OVERVIEW

On June 25, 2004, Illinois Power Company ("Illinois Power", "AmerenIP", "IP" or "Company") filed tariff sheets by which it proposed a general increase in its base rates for gas service. The proposed increase is applicable only to customers' base rates, e.g., the facilities, delivery, demand and related charges paid by customers to compensate IP for delivering gas (whether IP-supplied or customer-supplied) to the customer. In addition, IP proposed various changes to its Standard Terms and Conditions, to its Rules, Regulations and Conditions Applying to Gas Service, and to terms and conditions for various individual services, including IP's transportation services.

Illinois Power last received an increase in base gas rates in 1994 (Docket 93-0183), at which time IP's gas revenues were increased by 6.1%. IP's last gas rate increase prior to Docket 93-0183 was granted in 1982 (Docket 82-0152). In addition, Illinois Power's gas rates were decreased in 1984 (Docket 84-0265), in a proceeding initiated by the Company. Over the past 24 years, Illinois Power has received only two increases, offset in part by a decrease, in its base gas rates. (Rev. IP Ex. 1.1, pp. 4-5)

Illinois Power's original filing proposed a revenue increase of approximately $39.75 million, or approximately a 9.5% increase in present gas utility revenues, based on weather-normalized test year 2003 consumption. As a result of the acceptance by IP of adjustments proposed by Staff and intervenors, additional adjustments proposed by IP during the course of the case, corrections to various data and calculations underlying IP's proposed gas revenue requirement, and finally, a Stipulation entered into by IP and Staff (the "Stipulation") as to most of the remaining contested revenue requirements issues, there are now only two contested revenue requirements issues outstanding.[1] The two remaining revenue requirements issues involve the base gas inventory value for the Hillsboro Storage Field and the used and useful status of the Hillsboro Storage Field. Both of these issues are rate base issues. In light of the resolution of all other revenue requirements issues, the revenue increase that should be approved in this case would be at least $11,336,000 (assuming Staff's positions on the two remaining revenue requirements issues are fully adopted by the Commission) and at most $14,227,000 (assuming IP's positions on the two remaining issues are fully adopted). The calculations of these two revenue increase amounts are shown on Appendices A and B, respectively, to the Stipulation.[2] These revenue increase amounts are approximately 28.5% and 35.6%, respectively, of IP's originally filed increase request.[3]

Section II of this Brief addresses the two remaining revenue requirement issues. The Hillsboro base gas inventory issue involves an adjustment, recommended by Staff witness Lounsberry, to reduce Illinois Power's proposed rate base amount for base gas inventory in its storage at IP's Hillsboro Storage Field. The Hillsboro used and useful issue arises from Staff witness Lounsberry's contention that the Hillsboro Storage Field should be considered only 53.44% used and useful. As shown in Section II below, both of Mr. Lounsberry's adjustments

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[1]No other party has objected to the resolution of the contested revenue requirements issues provided for in the Stipulation between IP and Staff.

[2]AmerenIP is filing a partial draft order, which has been circulated for comment among the parties, that covers the development of the rate base (other than the two remaining revenue requirements issues) and operating expenses and the rate of return, and summarizes all of the now-uncontested adjustments to rate base and operating expenses that should be included in determining the revenue requirement.

[3]One reason that the base revenue increase based on the Stipulation is such a low percentage of IP's original request is that the Stipulation resolves virtually every remaining contested revenue requirements issue between IP and Staff in favor of Staff's position. Further, the Stipulation provides for a lower rate of return on rate base than Staff's original recommendation in this case.

should be rejected in their entirety. The record fully supports IP's base gas inventory amount for the Hillsboro Field, and demonstrates that the Hillsboro Storage Field is fully used and useful.

Although it is not a contested issue, Illinois Power calls to the Commission's attention that the filing in this case includes a request for approval of revised gas utility depreciation rates. IP's current depreciation rates were established over ten years ago. The proposed gas depreciation rates are supported by a depreciation study performed by Foster Associates. (IP Ex. 11.3) The proposed gas depreciation rates are, in general, lower than the current rates -- the proposed accrual rates are lower than the current rates for 27 of the 36 gas plant accounts. Based on December 31, 2003 plant balances, adoption of the new depreciation rates would reduce annualized depreciation expense by $3,200,674. (IP Ex. 11.1, p. 16) The Staff witness testified that the depreciation study was warranted given the age of IP's depreciation rates, that the results appear reasonable, and that Staff has no objection to adoption of the proposed depreciation rates. (Staff Ex. 2.0, pp. 15-16) Accordingly, the Commission's Order in this proceeding should approve IP's proposed gas utility depreciation rates.

In addition to the two remaining revenue requirements issues, a number of issues remain with respect to the cost of service study and allocation of the overall revenue requirement to the customer classes, rate design, and tariff terms and conditions, including certain terms and conditions of IP's Service Classification ("SC") 76, Transportation of Customer-Supplied Gas with Best Efforts Backup, and proposed new SC 66, Seasonal Gas Service.[4] These issues are addressed in Sections III and IV of this brief.[5] As shown in those sections, IP's positions with

[4]SC 66, Seasonal Gas Service, replaces and consolidates current SC 67, Firm Gas Grain Drying Service, and SC 68, Seasonal Gas Asphalt Service.

[5]AmerenIP and Staff entered into a second stipulation (the "Tariff Stipulation") to resolve certain issues concerning IP's transportation tariffs, and those resolutions are reflected in the discussion in Section IV of this Brief.

respect to the cost of service study, interclass revenue allocation, rate design and tariff terms and conditions issues still in dispute should be adopted by the Commission.

II. RATE BASE – HILLSBORO STORAGE FIELD ISSUES

A. Introduction

There are two remaining revenue requirements issues in this case, both relating to Illinois Power's Hillsboro Storage Field. Both issues arise from proposals by Staff witness Lounsberry to reduce the amount of rate base components pertaining to the Hillsboro Field. The two adjustments have a common basis, namely, an injection metering error that occurred at the Hillsboro Field over the period 1993 through 1999 and was not fully recognized until 2003. As a result of this error, over a period of years Illinois Power injected less gas into the Hillsboro Field inventory than the Company thought it was injecting based on the metering information.

The base gas inventory issue involves Mr. Lounsberry's recommendation that the Commission disallow $10,367,838 of the base gas inventory in the Hillsboro Field, which represents the cost of base gas reinjected by IP into the Field to replace base gas that had been unknowingly withdrawn as a result of the injection metering error. Specifically, Mr. Lounsberry did not accept IP's determination of the amount of the Hillsboro base gas inventory that was withdrawn (and has now been replaced) as sufficiently reliable for ratemaking purposes. He proposed that the Commission instead continue to use the base gas inventory value for the Hillsboro Field that was included in rate base over ten years ago in IP's last gas rate order, Docket 93-0183.

The Hillsboro Storage Field used and useful issue involves Mr. Lounsberry's recommendation that the Commission find the Hillsboro Storage Field to be only 53.44% used and useful.[6] (Staff Ex. 17.0R, p. 24) Mr. Lounsberry's proposed used and useful disallowance arises from the facts that over the period 1994-1995 through 2003-2004, IP did not cycle the design amount of working gas inventory (7.6 bcf) from the Field during each winter heating season, and that for the winter seasons of 1999-2000 through 2002-2003, the expected peak day deliverability rating of the Field was reduced from 125,000 mcf/day to 100,000 mcf/day.[7] (See Staff Ex. 7.0, p. 25) These deliverability issues resulted from the depletion of the Hillsboro gas inventory that occurred over time due to the injection metering error.

The Company opposes both adjustments. With respect to the base gas inventory issue, the amount by which the Hillsboro gas inventory was depleted and thus needed to be replaced was determined using three independent analytical approaches, and is reasonable, reliable, and based on state-of-the art techniques for determining the volumes in place in a gas or oil reservoir. IP's analyses were implemented using an extensive database of information concerning the characteristics of the Hillsboro storage reservoir. Mr. Lounsberry has leveled only isolated criticisms of the techniques that IP employed, and has offered no alternative estimate. Further, he has provided no justification for continuing to use the base gas inventory value from the Commission's 1994 gas rate order for IP. With respect to Mr. Lounsberry's proposed used and useful disallowance, the record establishes that the Hillsboro Storage Field meets the statutory tests of being "needed" to meet customer demand and "economically beneficial" in meeting

[6]Consistent with past Commission practice, the impact of the used and useful adjustment as proposed by Staff is that the common equity component of the overall allowed rate of return would not be applied to the non-used and useful portion of the Hillsboro Storage Field investment; instead, only the non-equity return components of the overall rate of return would be applied to the non-used and useful portion of Hillsboro investment. (See Staff Ex. 1.0R, pp. 7-9)

[7]As discussed in greater detail below, the Hillsboro Field has been restored to its previous peak day capability rating of 125,000 mcf/day beginning with the 2003-2004 winter season, and the Field's ability to achieve this peak deliverability has been confirmed by testing on January 30, 2004. (Rev. IP Ex. 13.1, pp. 6-7)

customer demand. Further, the analysis Mr. Lounsberry performed to arrive at his proposed 53.44% used and useful portion of Hillsboro is based on out-of-date historical information that does not reflect the current operating condition of the Field and is flawed in other respects as well. Even a used and useful calculation of the same form that Mr. Lounsberry employed, but implemented using more up-to-date data, shows that the Hillsboro Field is no less than 84% used and useful.

Section II.B following describes the history of the Hillsboro injection metering error, which is common to both the base gas inventory issue and the used and useful issue. The specifics of the two issues are then addressed in Sections II.C and II.D, respectively.

B. <u>Hillsboro Injection Metering Error</u>

Illinois Power has had a storage field at Hillsboro since 1972; however, the Field was substantially upgraded in the early 1990s. As a result of the upgrade, which was completed in 1993, the peak day deliverability of the Hillsboro Field was increased to 125,000 mcf/day and the expected working gas volume of the Field was increased to 7.6 bcf. Injections into the Field in connection with the upgrade increased the total inventory in the Field to 21.7 bcf, consisting of 14.1 bcf cushion gas and 7.6 bcf working gas. (Rev. IP Ex. 14.1, p. 4) The expanded Hillsboro Field initially performed as expected. For the 1993-1994 through 1996-1997 heating seasons, the Field tested at a peak day deliverability value at or above 125,000 mcf/day in each season. Further, in the 1993-1994 winter, approximately 7.6 bcf of working gas was cycled (i.e., withdrawn for delivery to customers) from the Field. In subsequent winters, however, the amounts of working gas cycled from Hillsboro declined, from 5.95 bcf in 1994-1995 to 4.1 bcf in 1998-1999. Based on several years of declining annual deliverability, IP first observed that there could be a potential problem with the Hillsboro Field following the 1995-1996 winter withdrawal season. (*Id.*, p. 5)

Over the ensuing several years, Illinois Power devoted considerable effort, resources and attention to attempting to determine the source of the declining deliverability at the Hillsboro Field. IP initially investigated whether there was a reservoir problem, i.e., whether gas injected into the Field was migrating from the underground structure or whether the shape of the structure was different than had been expected, with the result in either case being that gas injected into the Field was moving to areas where it could not be reached by the Field's withdrawal wells. IP had a vertical seismic profile and then a three-dimensional ("3-D") seismic profile of the Field prepared by outside consultants; these analyses resulted in the preliminary conclusion that approximately 3.5 bcf of gas had migrated to another underground structure to the northeast of the Hillsboro Field. (*Id.*, p. 7) Based on these results, in 2000 IP drilled a new well to the northeast of the Hillsboro Field where it was believed a sub-structure existed to which gas had migrated from the main reservoir. However, when the well was drilled, it was discovered that there was not a separate sub-structure in that area. (*Id.*, pp. 11-12) Thereafter, Illinois Power conducted a number of additional analyses to determine if there was a reservoir problem, including conducting crosswell seismic surveys[8]; performing well stimulation treatments on a total of six of the wells at the Hillsboro Field[9]; performing additional neutron log analyses[10];

[8]A crosswell seismic survey is a high resolution process capable of resolving underground features much smaller than those visible with a 3-D surface seismic analysis. (Rev. IP Ex. 14.1, p. 12)

[9]Well stimulation treatments consist of injecting chemicals through a well bore and into the reservoir to attempt to clean up barriers near the well bore that may be interfering with injections or withdrawals. (Rev. IP Ex. 14.1, p. 13)

[10]A neutron log is a survey done inside a gas well that can determine the water-gas mix within a reservoir by measuring the hydrogen ion concentration; this information was used in analyzing

conducting flame ionization surveys[11]; analyzing whether gas leakage was occurring from plant piping or equipment back into the Field (none was discovered); and other analyses. These analyses continued into 2003. (*Id.*, pp. 12-15)

While IP was investigating whether there was a reservoir problem with the Hillsboro Field, it was also investigating whether there were problems with the injection and withdrawal metering at the Field.[12] In August 1999, IP retained Peterson Engineering to conduct an audit of the metering at the Hillsboro Field. (Rev. IP Ex. 14.1, pp. 7-8) The Peterson audit identified two metering problems:

- Two new turbine injection meters installed at the Field were over-registering gas injections under certain operating conditions. When the compressors that were situated near the turbine meters were operating at 50% loadings, they caused the meters to over-spin, thereby recording a greater amount of gas than was in fact passing through the meters. The over-registration was determined to be 26% when the compressors were operating at 50% loadings.[13] (*Id.*, p. 8)

- The orifice opening on the orifice meter at the south withdrawal secondary run was smaller than the value that had been stamped on the equipment at the

(i) whether there was gas leakage from the reservoir formation (none was detected) and (ii) whether the thickness of the "gas bubble" within the reservoir was changing (it was determined that the gas bubble in the Hillsboro reservoir was thinning). (Rev. IP Ex. 14.1, p. 14; IP Ex. 17.1, p. 8)

[11]Flame ionization tests are conducted at ground level to identify any migration of gas at the surface that would not be detected through neutron logs. No surface gas leakage was identified. (Rev. IP Ex. 14.1, p. 14)

[12]The metering at the Hillsboro Storage Field consists of (i) the plant metering, at which all gas coming into the Field for injection is measured (from 1993 to 2003-2004, this metering consisted of the turbine injection meters hereinafter discussed), and (ii) injection and withdrawal metering at each of the 14 inject/withdraw wells located throughout the Field, at which gas is actually injected into the Field and subsequently withdrawn for delivery to customers.

[13]When the compressors were operated at close to full loadings, however, only minimal over-registration occurred on the turbine meters. (Rev. IP Ex. 14.1, p. 8)

> manufacturer's plant.[14] The orifice value stamped on the equipment was the same value that IP had ordered, but the size of the opening was actually smaller than the value stamped on the orifice plate. This meant that less gas was being withdrawn from the Field than had been believed, because the (incorrect) size of the orifice opening is a value that is input into the programmable logic controller for the meter, which calculates the value of gas passing through the meter. (*Id.*, pp. 8-9)

To correct the turbine metering measurement errors, operating procedures were implemented to avoid the 25% and 50% compressor loading levels, since these were the compressor loading levels that caused the most significant over-registration on the turbine meters. Additionally, the static pressure sensing points for the turbine meters were relocated to improve their accuracy. These steps, which were recommended by Peterson Engineering, were implemented in May 2000.[15] To correct the orifice metering problem, the correct, actual size of the orifice opening was input into the programmable logic controller so that it would correctly calculate the amount of gas passing through the meter. (*Id.*, pp. 10-11)

The corrective actions taken in response to the Peterson Engineering audit largely mitigated the metering problems at the Hillsboro Field by the Spring of 2000. Thus, the actual injection measurement error occurred over the period 1994-1999. (Rev. IP Ex. 14.1, p. 16) However, at the time the corrective actions were taken it was believed that the injection metering error and the orifice withdrawal metering error were approximately offsetting. (*Id.*, pp. 9, 11) Moreover, for the 1999-2000 winter season, based on testing results as well as the overall accumulated experience of reduced deliverability from the Hillsboro Field over the preceding several years, IP had reduced the expected peak deliverability rating from 125,000 mcf/day to

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[14]The principal gas withdrawal facility into the south pipeline from the Hillsboro Field is the primary run. The secondary run, on which the orifice metering problem was found, only operates occasionally, during periods of high withdrawal flow rates. (Rev. IP Ex. 14.1, pp. 8-9)

[15]Subsequently, in 2003 and 2004, the turbine injection meters were replaced with newer-technology ultrasonic meters that are not affected by operation of the compressors (and require less maintenance than the turbine meters). (Rev. IP Ex. 14.1, p. 10; IP Ex. 14.3, pp. 9-10)

100,000 mcf/day.[16] (*Id.*, pp. 18-19) Therefore, IP continued to investigate the source of the Hillsboro Field deliverability problem as described earlier.

A volumetric analysis of volume of gas in the Field in the Spring of 2002 indicated that there was approximately 5.5 bcf less gas in the Field than there had been in the Spring of 1993.[17] (*Id.*, pp. 15-16) This analysis, along with a comparison of the gas injected as measured by the plant injection meters (the turbine meters) to the gas being injected as measured by meters at the individual injection wells, led to the conclusion that the turbine meters had been recording substantially more gas than had actually been injected into the Field over an extended time period, and that as a result the gas volumes in the Field had been substantially depleted as a consequence of the measurement errors. Further, the other analyses that IP had conducted to attempt to determine if there was a reservoir problem with the Hillsboro Field enabled the Company to rule out the likelihood that the source of the gas depletion was a structural or geological problem. (*Id.*, pp. 16-17)

The next section of this Brief describes how Illinois Power determined the amount by which the gas inventory in the Hillsboro Storage Field had been depleted, why the Company's estimate is reasonable and reliable, and why Mr. Lounsberry's disallowance of Hillsboro base gas inventory should be rejected.

[16]The peak day deliverability rating of the Hillsboro Field has been subsequently restored to 125,000 mcf/day, prior to the 2003-2004 winter season. This deliverability has been confirmed by testing, and the peak day rating continues at 125,000 mcf/day for the 2004-2005 winter season. (Rev. IP Ex. 14.1, p. 19)

[17]The volumetric analysis uses data on the volume of the reservoir and gas-water saturation data from the neutron logs to develop an estimate of the gas volume actually in the reservoir. (Rev. IP Ex. 14.1, p. 15)

C. Hillsboro Base Gas Inventory Adjustment

1. IP's Adjustments to the Hillsboro Gas Inventory Amounts and Staff Witness Lounsberry's Proposed Disallowance

In 1999, based on the actual operating performance of the Hillsboro Field to that point, Illinois Power made accounting entries to reflect the amount of gas believed to be in the Field at that time, based on then-available information. While the total amount of gas in the Field per IP's books was not changed, the total inventory was reallocated between working gas and base gas. Specifically, 3.6 bcf of gas with a book value of $8,460,000 was shifted from the working gas account to the recoverable base gas account. This resulted in accounting balances of 17.7 bcf of non-recoverable and recoverable base gas and 4.0 bcf of working gas in the Field. Subsequently, based on the analysis completed in 2004 of the gas inventory depletion that had resulted from the injection metering error (described below), IP reversed the 1999 accounting entries. The analysis completed in 2004 determined that there had been an inventory depletion of 5.8 bcf, of which 1.8 bcf was recoverable base gas and 4.0 bcf was working gas. In other words, 1.8 bcf had been withdrawn from recoverable base gas and supplied to customers as a result of the injection measurement error, and needed to be restored.[18] (Rev. IP Ex. 13.1, pp. 4-5)

Reinjection of the depleted 1.8 bcf of base gas has been completed. Illinois Power re-priced the base gas inventory to reflect the withdrawals and reinjection, resulting in a total value for the base gas inventory of $31,044,200, which is $10,367,838 higher than the base gas value recorded in 1993 of $20,676,363.[19] (*Id*., p. 5) However, since the $8,460,000 adjustment to base

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[18]The cost of the base gas that had been withdrawn and supplied to customers is being recovered through the PGA beginning in 2004. (Rev. IP Ex. 13.1, p. 5)

[19]The repricing was based on the same method of monthly injection/withdrawal pricing used for working gas inventory: (i) withdrawals are priced at the average price of the storage field at the end of the previous month, and (ii) injections are priced at the average price of gas purchased during the month. (IP Ex. 2.1, p. 17)

gas inventory recorded in 1999 was on IP's books and records at December 31, 2003, the amount of the pro forma rate base adjustment to test year balances proposed by IP is $1,908,000 (i.e., $10,368,000 minus $8,460,000). (IP Ex. 2.1, p. 17)

Staff witness Lounsberry, however, recommended that the base gas inventory amount be reduced by the entire $10,367,838 of reinjected Hillsboro base gas inventory, and that the rate base established in this case include only the value of recoverable base gas included in rate base in the 1994 gas rate order, at the time of the Hillsboro Field expansion. (Staff Ex. 7.0, p. 8) His recommendation is not based on any assertion that the depletion and subsequent need to restore the base gas inventory resulted from imprudent management by IP – nowhere in his direct or rebuttal testimonies does he contend that IP acted imprudently. Rather, his recommendation is based solely on his assertion that he does not consider IP's calculation of the amount by which the Hillsboro base gas inventory was depleted to be "accurate enough." (*Id.*)

Although he did not dispute that the Hillsboro Field base gas inventory was depleted due to the metering error and needed to be replaced, Mr. Lounsberry nonetheless recommended that rate base incorporate only the 1994 base gas value, which is clearly obsolete and no longer representative of the value of the base gas in the Field. Further, although Mr. Lounsberry stated several concerns about the methods IP used to estimate the Hillsboro inventory depletion, he offered no alternative calculation or estimate. The effect of Mr. Lounsberry's position is to assume that *no* base gas has been withdrawn and replaced. (Rev. IP Ex. 13.1, p. 5; IP Ex. 14.3, pp. 2-3) Additionally, he made the totally inappropriate recommendation (unsupported by any witness from the Commission's Accounting Department or Financial Analysis Division) that IP should seek to recover the value of the *base gas* that has been *reinjected* into the Field through the Purchased Gas Adjustment ("PGA"), even though the reinjected base gas is not gas that is to be withdrawn to supply to customers. (Staff Ex. 7.0, pp. 8, 20)

As shown below, IP determined the depleted base gas inventory volumes using three separate methods. Two of those studies were performed by a qualified outside consultant under IP's direction, and the third was prepared internally. The resulting estimate of the gas inventory depletion and reinjection is reasonable, reliable and sufficiently accurate to be the basis for a rate base component. The bases for the three studies and the resultant estimates have been described in IP's evidence in this case, and considerably more detail was made available to Staff through discovery. (IP Ex. 14.3, p. 2) In response, Mr. Lounsberry offered only isolated criticisms of the three studies, and, as noted, provided no alternative estimate. Further, the majority of Mr. Lounsberry's criticisms were directed at the study on which IP placed the least reliance in determining the amount of the Hillsboro Field inventory depletion (i.e., the well chart study). (*Id.*) Mr. Lounsberry's position should be rejected, and the Hillsboro base gas inventory value developed by Illinois Power should be included in rate base in this proceeding.

2. Illinois Power's Development of the Amount by Which the Hillsboro Gas Volumes Had Been Depleted

Illinois Power determined the overall Hillsboro Storage Field inventory depletion of 5.8 bcf using three independent studies: a reservoir modeling (reservoir simulation) analysis, a volumetric analysis and a well metering (well chart integration) analysis. The three studies are summarized below. Although all three studies were considered in determining the overall 5.8 bcf value, IP placed the greatest reliance on the reservoir modeling study and the least reliance on the well metering analysis.[20] (Rev. IP Ex. 14.1, p. 18; IP Ex. 14.3, pp. 2, 11)

[20]IP Exhibit 14.2 sponsored by Messrs. Hood and Kemppainen is a report prepared by IP that summarized the metering analysis as well as the overall conclusion, and IP Exhibit 17.5 is the

a. <u>Reservoir Modeling</u>

IP witness Timothy Hower, President of MHA, presented testimony describing the reservoir modeling and volumetric analysis studies that his firm performed for IP as part of the overall determination of the Hillsboro gas inventory depletion. MHA is an international geology and engineering consulting firm. Mr. Hower holds B.S. and M.S. degrees in Petroleum and Natural Gas Engineering from Penn State University, and is a registered professional engineer in Colorado and Wyoming. He has been involved in the design, analysis and implementation of gas storage reservoirs for almost 15 years, and has a significant base of experience in Illinois working on gas storage reservoirs of several different companies. He is engaged in working on and managing reservoir studies on oil, gas and gas storage reservoirs worldwide. He has authored technical papers on gas storage and is co-author of an industry textbook entitled "Managing Water-Drive Gas Reservoirs" published by the Gas Research Institute. Mr. Hower has worked as a consultant for IP since 1992 and in that role has, among other tasks, assisted IP with reservoir studies for both its Hillsboro and Shanghai Storage Fields. (IP Ex. 17.1, pp. 1-3)

Mr. Hower testified that the database of information available for the Hillsboro Storage Field, on which IP drew in conducting its reservoir modeling analysis (and its volumetric analysis), is "one of the most comprehensive data sets that I have seen in my experience evaluating gas storage reservoirs." Through the expenditure of substantial resources, IP has collected or commissioned 3-D seismic data, core data, special core analyses studies, neutron logs, detailed petrophysical and geological interpretations, a 3-D geological model, and a numerical reservoir simulation model for the Field. Using this data, IP employed the most sophisticated analysis techniques available in estimating the volume of gas in place in the

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report prepared by Mr. Hower's firm, Malkewicz Hueni Associates ("MHA") that summarized the volumetric analysis and reservoir modeling study performed by MHA for IP.

Hillsboro Field (and thus the amount of the inventory depletion). The techniques IP employed are state-of-the art techniques which adhere to standard, accepted industry practice for evaluating gas storage reservoirs, and are used by gas storage operators throughout the world. These techniques are accepted by the Society of Petroleum Engineers and the Securities and Exchange Commission ("SEC"), who are responsible for outlining the standards used by the oil and gas industry in the assessment of hydrocarbon volumes, such as the amount of proved underground reserves. These same techniques are used by major publicly-held oil and gas companies in developing their estimates of reserves for purposes of public financial reporting. Mr. Hower stated that there is not a better, more reliable technique than what IP used to determine the gas volumes in place at the Hillsboro Field.[21] (IP Ex. 17.1, pp. 5-6; IP Ex. 17.6, pp. 2-3)

Mr. Hower described the reservoir modeling analysis that was conducted to estimate the gas volumes in place at the Hillsboro Field:

- A detailed 3-D geological model was constructed for the Hillsboro gas reservoir using 3-D seismic data and well logs from the injection and withdrawal wells at the Field.[22] The 3-D model contained an interpretation of the structure of the reservoir, specifically how it varies from point to point across the Field, as well as a description of the porosity, or available pore space, in the reservoir interval.[23] (IP Ex. 17.1, pp. 7-8)

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[21]Staff witness Lounsberry did not identify any different techniques that IP should or could have used. (IP Ex. 17.6, p. 3)

[22]Acquisition and interpretation of 3-D seismic data involves measuring the travel time of a sound wave propagated through the sub-surface. The signal reflects off the various rock formations and bounces back to the surface where it is recorded. The structure of the reservoir is identified because the travel time of the reflected signal from structurally high locations is shorter than in areas where the reservoir is deeper or farther below the surface. This process is conducted across the entire reservoir. The recorded data is processed to yield a 3-D image of the reservoir. (IP Ex. 17.1, p. 8)

[23]As described in Section II.C.2.b below, the 3-D geological model was also utilized in connection with the volumetric analysis.

- The 3-D model was used to construct a reservoir simulation model for the Hillsboro Field, including an interpretation of the structure and stratigraphy of the storage reservoir and caprock.[24] The model was calibrated, or matched, against observation well pressures, shut-in field pressures, gas saturation data from neutron logs performed in Fall 2003, and gas-water contact levels from the Fall 2003 neutron logs.[25] (*Id.*, p. 10)

- The reservoir simulation model was run using different injection rate schedules. Each case assumed a different volume of gas was injected over the time period in question (1994-1999) at Hillsboro. After each case was run, the results from the model (well pressures, field pressures, gas saturations and gas-water contact levels) were compared to actual field measurements. The case which provided the best match of simulation results to the actual measured data was the case that produced a total inventory volume in place of 16.8 bcf, or a variance (shortfall) of 5.8 bcf from the total inventory volume per IP's books. (*Id.*)

Mr. Hower explained that the reservoir simulation model approach is superior to the other two analyses conducted by IP because the reservoir modeling approach utilizes all of the available data (3-D seismic, core data and special core analyses, neutron logs, petrophysics and pressures) and provides a dynamic prediction of the reservoir's behavior over time. (*Id.*, p. 11) This latter point is relevant because the task at hand is to determine the volumes of gas actually injected into the reservoir over a multi-year period. The Hillsboro gas volume depletion of 5.8 bcf calculated using the reservoir modeling approach was equal to the final value that IP adopted after also taking into account the results of the other two analyses.

Staff witness Lounsberry expressed two concerns about the use of the reservoir simulation model. Neither concern warrants disregard of the results of this approach, nor supports Mr. Lounsberry's proposed disallowance. *First*, he asserted that "there is a limitation as to what the model can do" because the Hillsboro Field covers an area of 8.2 square miles and has

[24]"Stratigraphy" refers to the vertical sequence or vertical layering of rock formations in the sub-surface. This typically includes identifying different sub-surface beds of sandstones, shales, limestones and coals. (IP Ex. 17.1, p. 10)

[25]"Shut-in" refers to the status of the storage field or to individual wells when neither injections or withdrawals are occurring.

a total of 24 wells, from which data was used in the model. He opined that he would not suggest using outputs from the model to make "concrete decisions" regarding rates. (Staff Ex. 7.0, p. 18; see also Staff Ex. 17.0R, pp. 18-20)

Mr. Hower pointed out, however, that reservoir simulation is routinely used to evaluate hydrocarbon reservoirs that are much larger than the Hillsboro reservoir and contain significantly fewer wells. He reiterated that the reservoir simulation techniques adhere to the standards defined by the Society of Petroleum Engineers and the SEC and are used by companies, financial institutions and countries as a basis for investing hundreds of millions of dollars. He stressed that these are the state-of-the art techniques, regardless of the ultimate use to be made of the volume estimate (e.g., setting utility rates or some other purpose). (IP Ex. 17.6, pp. 2-3, 5; IP Ex. 17.1, p. 13) Further, reservoir simulation models are effective specifically when used to evaluate gas storage reservoirs, including aquifer storage such as Hillsboro. Reservoir simulation models are used throughout the industry to evaluate and optimize the performance of gas storage reservoirs and as a tool in realizing the full potential of underground storage fields in terms of volume and withdrawal rates, and in optimizing the design (including number of wells) and operation of underground storage facilities. (IP Ex. 17.1, pp. 13-14) Mr. Hower emphasized that reservoir simulation modeling is appropriate for use in connection with an aquifer storage reservoir such as Hillsboro where there is uncertainty as to the amount of gas that has been injected over time and the objective is to determine the volumes of gas in place in the reservoir (and thus the amount of the inventory depletion) in light of this uncertainty. (IP Ex. 17.6, pp. 3-5)

Second, Mr. Lounsberry asserted that a reservoir model is dependant on historical information from the storage field but that there were problems with gas measurement data at

Hillsboro starting in 1994, and that the reservoir model had only been matched to very recent (2003) field data. (Staff Ex. 7.0, pp. 18-19; Staff Ex. 17.0R, pp. 20-22) Mr. Hower demonstrated that Mr. Lounsberry's assumptions were incorrect and his concern was invalid.

Specifically, the Hillsboro simulation model was not developed using only 2003 field data. Rather, it was calibrated and matched against data collected over the entire life of the Field, from 1974 forward. The model was matched to all observation well pressures available for the entire life of the Field and to all shut-in field pressures available for the entire life of the Field. Data was used for periods in which Hillsboro operated at its full "design" capacity. The model was then run to simulate the operation of the Field during the historic periods when the measurement error occurred, in order to determine the historic injection schedule best matching the known, historic field data. (IP Ex. 17.6, pp. 6-8)

More generally, the Hillsboro reservoir simulation model was constructed on a foundation of known, accurate data such as 3-D seismic, core data, special core analyses, petrophysical calculations and measurements of well and field data. As Mr. Hower emphasized, this was a highly sophisticated data base of information about the Hillsboro reservoir, and it consisted of known data. The only data item in question was the historic (1994-1999) gas injection volumes, and thus the reservoir model was used to solve for this data item, by performing numerous model runs using various assumed gas injection schedules over time, and selecting the run (and thus the historic gas injection schedule) that produced the best match with the known, measured field data. (IP Ex. 17.1, p. 14; IP Ex. 17.6, pp. 5-6)

In summary, the reservoir modeling approach used to determine the gas volumes in place in the Hillsboro Field (and thus the amount of the inventory depletion) was relevant, robust and appropriate; it was based on a substantial quantity of known data covering the history of the

Field; and it constituted a state-of-the-art, industry accepted technique that provided the best estimate possible of the gas volumes in the Field given the uncertainty as to the volumes injected over the 1994-1999 period. (IP Ex. 17.6, pp. 3-6) Mr. Lounsberry's few concerns fall far short of providing any reason to not rely on the Hillsboro inventory depletion value developed using the reservoir simulation model.

b. <u>Volumetric Analysis</u>

The second method Illinois Power used, volumetric analysis, was conducted as follows:

- As noted earlier, a detailed 3-D geological model was constructed for the Hillsboro gas storage reservoir. (IP Ex. 17.1, pp. 7-8)

- Neutron logs compiled in the Fall of 2003 were evaluated to determine the gas saturation and the location of the gas-water contact within the reservoir interval. The location of the gas-water contact provides the base of the gas bubble in the reservoir. [26] (*Id*., p. 8)

- With an interpretation of the top of the reservoir (from the 3-D geological model) and estimates of the base of the gas bubble and of the gas saturation within the bubble (from the neutron logs), the gas volume in place as of November 2003 could be calculated. (*Id*., pp. 8-9)

Using this technique, the volume of gas in place in the Hillsboro Field was calculated to be 14.2 bcf, which represented a shortfall of 8.4 bcf from the gas volumes indicated by accounting records based on the historic (but inaccurate) injection records. (*Id*., p. 9) This was the smallest estimate of the gas volumes in place, and thus the largest estimate of the inventory depletion, developed by the three techniques that IP employed.

Staff witness Lounsberry provided no specific criticisms or concerns regarding the volumetric analysis in either his direct or his rebuttal testimony.

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[26]As noted earlier, a neutron log performed at a well measures the hydrogen ion concentration of the fluids in the reservoir in the vicinity of the well bore. Since the hydrogen ion concentrations of gas and water are different, this technique enables the operator to determine the water-gas mix in the reservoir. (IP Ex. 17.1, p. 8)

c. **Metering (Well Chart) Analysis**

The third approach that Illinois Power used to determine the Hillsboro inventory depletion was a comparison of injected volumes as measured by the plant turbine meters to injected volumes as measured by the injection meters at the 14 individual wells at the Field, during historic periods when the turbine measurement error was occurring. Specifically, this comparison was conducted using data from the injection months in the years 1994, 1995, 1998 and 1999. To conduct this analysis, data was needed from well chart logs taken from the injection metering at each of the 14 wells. The injection data from the well charts then needed to be integrated on a daily basis to develop a total injection volume for the day that could be compared to the volume injected as measured (incorrectly) on the plant turbine meters. The well charts for 1994 and 1998 were sent to an outside chart integration service to be integrated using custody transfer computation processes, while the well charts for 1995 and 1999 were integrated by IP employees using an in-house chart integration program. Using the comparisons between the daily volumes recorded on the plant turbine metering and the daily volumes injected at the wells as determined from the integrated well charts, a percentage error (correction factor) for the injection volumes measured at the turbine meters was developed for each injection season. These percentage errors were: 1994, (22.1)%; 1995, (7.0)%; 1998, (12.7)%; and 1999, (8.9)%.[27] (Rev. IP Ex. 14.1, pp. 21-23; IP Ex. 14.2, pp. 3, 6-10)

[27]The analysis was not performed using data for 1996-1997 because the interstate pipelines had changed their definitions of the gas "day", which determined the measurement day used to record injected volumes at the plant turbine meters, from "noon to noon" to "9 A.M. to 9 A.M," but the gas day start time on the individual well meters was not re-set to coincide with the revised gas "day" until 1998. (Rev. IP Ex. 14.1, p. 23) (Whether the individual well meters are matched to the pipeline "gas day" is unimportant to the day-to-day operation of the inject/withdraw wells.) To overcome this problem would have necessitated that the well chart data be integrated on an hourly rather than a daily basis, which would have required considerably

The results of the well chart analysis indicated annual adjustments to the Hillsboro gas inventory of 1.4 bcf to 5.8 bcf, with an average value from the two years for which the well charts were sent to an outside service for integration of 4.9 bcf. (IP Ex. 17.1, p. 7) Further, the upper end of the range of the percentage errors developed through this approach, (22.1)%, is consistent with the inventory shortfall value of 5.8 bcf developed by the reservoir simulation modeling. (Rev. IP Ex. 14.1, pp. 17-18; IP Ex. 14.2, p. 4) Additionally, by November 2004, IP had reinjected an additional 2.6 bcf of gas into the Hillsboro Field with no gas yet seen at the Field's two key observation wells. These results confirm that the turbine meter correction factors calculated for the two years for which IP performed the chart integration in-house, 1995 (-7.0%) and 1999 (-8.9%), were too low. (Rev. IP Ex. 14.1, pp. 24-25)

Staff witness Lounsberry expressed several concerns about the well chart integration study. In fact, the majority of the concerns he expressed overall about the development of the Hillsboro inventory shortfall estimate were directed at the well chart study. Therefore, before addressing these concerns individually, Illinois Power emphasizes that of the three studies conducted, it placed the least reliance on the well chart integration study. (IP Ex. 14.3, p. 2) In fact, if IP had placed <u>no</u> reliance on the well chart analysis, its overall estimate of the Hillsboro gas inventory depletion would not have changed. The volumetric study and the reservoir simulation study indicated a range of gas inventory depletion of 5.8 bcf to 8.4 bcf. IP used the results of the well chart integration study to place the overall estimate at the bottom end of this range, i.e., 5.8 bcf. (*Id.*, p. 11) Illinois Power placed primary weight on the results of the reservoir simulation modeling and placed the least reliance on the results of the well chart integration analysis.

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more time to complete, and would have required that IP have two consecutive days of well chart data for all of the wells to match against each day of turbine metering data. (IP Ex. 14.3, pp. 5-6)

One area of concern expressed by Mr. Lounsberry about the well chart integration study was that Illinois Power should have used more days of chart data for 1994, 1995, 1998 and 1999, and should have had the well charts for 1995 and 1999 integrated by an outside vendor rather than in-house. (See Staff Ex. 7.0, p. 16 and Staff Ex. 17.0R, pp. 7-10) While there was much discussion in the record concerning the number of days of data used by the Company, the bottom line is that the number of days that could be used was limited by the number of days in each month for which IP had well charts available for all of the injection wells that had operated on that day. For some months there were as few as two days for which chart data for all wells was available, while for other months there were more than five days for which chart data for all wells was available. Overall, the well charts were integrated for virtually all the days in the 1994, 1995, 1998 and 1999 injection seasons for which IP had usable well chart data for all injection wells. Further, for 1994, the number of days of data that were used (in light of the foregoing limitation) constituted 25% of the total number of days on which gas was injected into the Field. The corresponding percentages for 1995, 1998 and 1999 were 15%, 19% and 15%, respectively. (IP Ex. 14.3, pp. 3-4)

With respect to Mr. Lounsberry's concern that the well charts for 1995 and 1999 were integrated by IP using an in-house program rather than by an outside chart integration service, IP acknowledges that the chart integration results using the in-house program may have been less accurate than the chart integration results produced by an outside service. (Rev. IP Ex. 14.1, pp. 22-23) However, IP placed greater reliance on the turbine metering correction factors calculated for the two years (1994 and 1998) for which the chart integration was performed by an outside service. Further, as discussed earlier, subsequent results in connection with re-filling the Field have shown that the calculated correction factors for the two years for which the well charts were integrated in-house were too low. (*Id.*, pp. 24-25; IP Ex. 14.3, pp. 10-11)

Another concern stated by Mr. Lounsberry with respect to the well chart analysis was that the 1999 Peterson Engineering metering audit report had observed that the orifice meters at the individual wells were not set up according to American Gas Association ("AGA") guidelines for orifice metering. He also referred to a statement in the Peterson Engineering report that "for well production gas metering, the metering measurements should not be used as an engineering basis due to the insufficient length of straight piping upstream of the orifice plates and a protrusion in the flow path." Thus, he contended that this metering is not sufficiently accurate to calculate the injections into the Field. (Staff Ex. 7.0, pp. 16-17; Staff Ex. 17.0R, p. 11)

However, the Peterson report stated that "the individual well metering was *reasonably accurate when injecting gas*, but not accurate for natural gas withdrawal" (emphasis supplied). The well chart data that IP used for the chart integration analysis was injection data only, not withdrawal data. With respect to the Peterson report's reference to the "well production" gas metering, this is an industry term that refers to withdrawal from the ground; thus, the statement Mr. Lounsberry cited was referring to the *withdrawal* metering attributes. With respect to the *injection* metering at the wells, the Peterson report stated: "For injection, the meter runs are in general accordance with AGA Report #3, Part II for the installed orifice plates." Again, in the well chart integration study, IP used well chart injection metering data, not withdrawal metering data. (Rev. IP Ex. 14.1, pp. 21-22; IP Ex. 14.3, pp. 7-8) Thus, Mr. Lounsberry's concern was completely misplaced.

A further concern expressed by Mr. Lounsberry about the well chart integration study was that IP did not integrate well charts for the 1996 and 1997 injection seasons. (Staff Ex. 7.0,

p. 17; Staff Ex. 17.0R, pp. 13-14) However, as described in footnote 27 above, there were valid reasons why well chart data for 1996 and 1997 were not used.

A final concern stated by Mr. Lounsberry with respect to the well chart integration analysis was that, according to his review of IP's study, IP applied a consistent correction factor for all months that the measurement error occurred. He contended that the turbine measurement error would have fluctuated from month to month because it was a function of the operating rate of the Hillsboro compressors which he believed would not operate at the same average speed every month. (Staff Ex. 7.0, pp. 17-18) However, the stated premise of his concern was incorrect: the three Hillsboro compressors are synchronous motor driven and operate at a constant speed. (Rev. IP Ex. 14.1, p. 25) Assuming that what Mr. Lounsberry really meant was that the compressors do not operate at constant loadings, his concern is still unfounded, because the compressor loadings are not a function of time. Rather, they are dependent on other factors such as suction pressure, outlet pressure, required hourly throughput, and the number of compressors on line, all of which can change on a daily basis. Therefore, using an annual correction factor (percentage error) representing an average of the daily data (which is what IP did) was appropriate. (*Id.*, p. 26; see also IP Ex. 14.2, pp. 3, 6-10) Further, since a given set of conditions affecting the compressor loadings was as likely to occur in 1994 as in 1999, the correction factor was independent of time. Accordingly, use of a constant correction factor from the well chart analysis was appropriate. (IP Ex. 14.3, pp. 11-12)

More generally, Mr. Lounsberry's final criticism concerning the "constant correction factor" is unfounded in the context of IP's overall development of the 5.8 bcf Hillsboro inventory depletion. Illinois Power did not use a single correction factor (percentage metering error) for the entire six-year period to develop an independent estimate of the injection shortfall. Rather, as described earlier, IP used the well chart analysis to develop a range of correction factors (i.e., an average correction factor for each of four years), and also ran the reservoir simulation model iteratively against various correction factors to find the percentage injection metering error (i.e., the actual gas injection history) that best matched the reservoir data as generated by the model. A gas injection history that reflected a 22% correction to the recorded injections per the turbine meters – which corresponded to the correction factor calculated by the well chart study for 1994 – produced an in-place volume estimate of 16.8 bcf (and thus an inventory shortfall of 5.8 bcf), which best matched the actual reservoir characteristics as generated by the reservoir simulation model. (IP Ex. 17.1, pp. 11-12; IP Ex. 17.5, pp. 1-2; Rev. IP Ex. 14.1, pp. 17-18; IP Ex. 14.2, pp. 3-4; IP Ex. 14.3, p. 12)

d. <u>Development of Overall Inventory Depletion Value</u>

As the foregoing subsections have described, Illinois Power employed three independent approaches to develop an overall value of the Hillsboro gas inventory depletion that resulted from the turbine injection meter measurement error over the period 1993-1999. The chart integration analysis measured gas volume by gas flow; the volumetric analysis measured gas volume based on a neutron log response to gas in the reservoir; and the reservoir simulation modeling measured volume by using sensitivity analysis to find an injection/withdrawal profile that matched the Hillsboro reservoir's pressure responses. (Rev. IP Ex. 14.1, p. 27)

The well chart integration analysis produced a range of average annual correction factors (percentage error) to the recorded injection data of (7.0)% to (22.1)%. The volumetric analysis produced a value of gas in place of 14.2 bcf, indicating an inventory depletion of 8.4 bcf. The reservoir simulation modeling produced a value of gas in place of 16.8 bcf (which matched an average percentage injection measurement error over the six-year period of 22%), indicating an inventory depletion of 5.8 bcf. The reservoir simulation technique, being recognized as superior to the other two techniques because it is a dynamic approach rather than a static approach, was given the primary weight. Further, the well chart integration analyses, which produced correction factors much more consistent with the 5.8 bcf shortfall estimate than with the shortfall estimate produced by the volumetric analysis, helped to confirm that the value produced by the reservoir simulation modeling should be adopted. (Rev. IP Ex. 14.1, pp. 17-18; IP Ex. 14.3, p. 11; IP Ex. 17.1, p. 11)

The overall inventory depletion value that Illinois Power developed was based on a detailed evaluation of the available comprehensive data base and used state-of-the art, industry-accepted techniques. (IP Ex. 17.1, pp. 5-6) The value of 5.8 bcf developed by the Company, including the 1.8 bcf base gas inventory depletion which has subsequently been reinjected, is reasonable and sufficiently reliable to use in establishing the base gas inventory value to be included in rate base in this proceeding. Certainly, there is no justification for adopting Mr. Lounsberry's recommendation to include only the 1993 value in rate base, which effectively assumes that *no* change to the Hillsboro base gas inventory value has occurred since 1993.

In addition to his six specific concerns about the studies conducted by Illinois Power, Mr. Lounsberry expressed one additional concern based on the fact that IP has indicated that it will engage in further study in the summer of 2005 to determine if further adjustments to the Hillsboro inventory are appropriate. He asserted that "my interpretation of this is that IP itself is not confident as to accuracy of its measurement." (Staff Ex. 7.0, p. 19) His "interpretation" is incorrect, and this concern, like Mr. Lounsberry's other concerns, does not support his recommendation to reject the adjustment to the Hillsboro base gas inventory amount produced by IP's current studies. (IP Ex. 14.3, p. 13)

While the 2005 analysis (which will incorporate data collected in the course of operations during the 2004 injection season and 2004-2005 withdrawal season), as well as other ongoing analyses to be conducted in the normal course, could result in some fine tuning to the 5.8 bcf inventory shortfall estimate, it is not expected to be altered significantly. (Rev. IP Ex. 14.1, pp. 26-27) Further, it is most likely that if the 5.8 bcf value is biased, it is biased to the low side, i.e., the most likely direction of any change in this value would be an *increase*. (IP Ex. 14.3, pp. 12-13) In any event, the fact that the 5.8 bcf inventory shortfall value could be revised in the future does not detract from the reasonableness of this value which IP has developed and presented in this case. (*Id.*, p. 12)

Accordingly, Illinois Power's adjustment of $1,908,000 to its booked December 31, 2003, base gas inventory, reflecting an overall adjustment of $10,367,838 to the 1993 Hillsboro base gas inventory amount included in rate base in Docket 93-0183, should be accepted, and Staff witness Lounsberry's recommendation and adjustment should be rejected.

3. Mr. Lounsberry's Position That IP Should Seek Recovery of the Additional Base Gas Inventory Cost Through the PGA Is Unfounded

Mr. Lounsberry also testified that rather than including the revised Hillsboro base gas inventory cost in rate base, Illinois Power should seek to recover the $10,367,838 increased cost of its base gas inventory through the PGA. (Staff Ex. 7.0, p. 20) This position is at odds with the Commission's PGA rule, and unfounded. While Illinois Power *is* currently recovering through the PGA the cost of the *original* Hillsboro base gas that was (unknowingly, due to the injection measurement error) withdrawn from storage and supplied to customers, the $10,367,838 amount is the cost of the gas that has been *reinjected* into the Field to restore the base gas inventory volume. (Rev. IP Ex. 13.1, p. 6) As Peggy Carter, AmerenIP's Manager of

Accounting, pointed out, Section 525.40(c) of the Commission's PGA rule (83 Ill. Adm. Code 525.40(c)) states: "The cost of gas estimated to be withdrawn from storage during the base period shall be included in the Gas Charge(s)." The $10,367,838 of base gas in question was not injected into the Hillsboro Field with the intention of withdrawing it to supply customers, and it has not in fact been withdrawn from storage to serve customers. Therefore, the cost of this base gas should be recovered through IP's base rates (i.e., as a rate base component), not through its PGA . (Rev. IP Ex. 2.35, pp. 52-53)

When Mr. Lounsberry was confronted with this response to his proposal, in IP's rebuttal testimony, he did not respond to it in his rebuttal testimony. Nor did Staff present any testimony from any witness from the Accounting Department or Financial Analysis Division to contradict Ms. Carter's analysis of the Commission's PGA rule or to support Mr. Lounsberry's proposal. In short, his proposal is completely unfounded and must be rejected.

D. Hillsboro Used and Useful Status

1. Overview

Staff witness Lounsberry contended that the Hillsboro Storage Field should be treated as only 53.44% used and useful for purposes of this case. (Staff Ex. 17.0R, p. 24) The underlying premise of his adjustment was that the Hillsboro Field had not been operating at the design levels indicated to the Commission in Docket 93-0183 when the investment in the 1993 expansion of the Field was placed into rate base: peak day deliverability of 125,000 mcf/day and annual working gas inventory cycling of 7.6 bcf.[28] (Staff Ex. 7.0, pp. 21-22, 24-25) He calculated his

[28]As noted in Sections II.A and B above, the declining deliverability of the Hillsboro Field resulted from the turbine injection meter measurement error that occurred over the 1993-1999 period. Because less gas was being injected into the Field during the injection seasons in these years than IP believed to be the case based on the turbine injection meter readings, the inventory in place was less than IP believed. As a result, IP was unable to cycle a full 7.6 bcf of working

53.44% used and useful percentage using data on the operation of the Field and gas and pipeline firm transportation ("FT") prices for the period 1999-2000 through 2003-2004. (Staff Schedules 7.06 and 17.01-17.03)

Mr. Lounsberry's proposed used and useful adjustment is flawed and should be rejected by the Commission, for numerous reasons. First and foremost, the record shows that at Hillsboro's *current* operating condition – which will be the operating condition of the Field when the new rates approved in this case go into effect – Hillsboro meets the statutory test of being "necessary" to meet customer demand and "economically beneficial" in meeting customer demand.[29] Even using, without change, Mr. Lounsberry's calculation of the gas cost savings produced by the Hillsboro Field in its reduced operating condition (a calculation which, as discussed below, is inaccurate because it is based on stale and out-of-date cost and operating data from prior periods), the annual gas cost savings that the Hillsboro Field provides for ratepayers (through the PGA) are *greater* than the annual revenue requirement associated with *fully* including the Field in rate base as 100% used and useful. In a recent case, Mr. Lounsberry used precisely this test – a comparison of a storage field's annual revenue requirement to the gas cost savings it produces – to argue that the storage field was not used and useful; yet in this case – in which such a test demonstrates that Hillsboro *is* used and useful – Mr. Lounsberry *failed* to employ such a test or to even acknowledge its appropriateness.

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gas during the winter seasons, and eventually needed to reduce the expected peak deliverability of the Field from 125,000 mcf/day to 100,000 mcf/day from 1999-2000 until 2002-2003.

[29]This is the case even though, as discussed below, the annual cycling capability of the Hillsboro Field has not yet been fully restored to the "design" value of 7.6 bcf.

Hillsboro is also "needed" because it provides winter season deliverability of gas that most likely could not be replaced through purchases of additional FT capacity from the interstate pipelines.[30]

Second, Mr. Lounsberry's specific calculations leading to his 53.44% used and useful calculation were flawed and inappropriate in numerous respects. Although he purported to use the three-year period 2001-2002 through 2003-2004 for his calculations, which he justified by citing prior Commission orders addressing used and useful issues, analysis of those orders demonstrates that in the context of this case he should have used the three-year period 2002-2003 through 2005-2006. By using an "earlier" three-year period, Mr. Lounsberry failed to properly reflect the current capability of the Field, and he thereby produced (by his methodology) an understated used and useful percentage. Further, for the price of additional pipeline FT capacity assumed in his calculations to be needed to make up for Hillsboro's reduced deliverability, Mr. Lounsberry used the price of an *intrastate* pipeline and thus failed to include the cost of interstate pipeline transportation from the gas producing fields in the mid-continent region or the Gulf Coast region to Illinois. His calculations therefore severely understated the cost savings provided by Hillsboro's peak day deliverability. Finally, Mr. Lounsberry's calculation of the seasonal gas savings produced by the Field was based on historic gas prices that were as much as five years old. The seasonal gas savings he calculated are therefore unrepresentative of the seasonal gas cost savings produced by the Field based on current gas price information. With these flaws corrected, application of Mr. Lounsberry's method shows Hillsboro to be no less than 84.33% used and useful. (Rev. IP Ex. 13.1, p. 14; IP Ex. 13.4)

[30]Mr. Lounsberry testified, "I do not know if there currently exists sufficient surplus pipeline capacity to replace the Hillsboro storage field." (Staff Ex. 17.0, p. 32)

Third, Mr. Lounsberry's used and useful calculation methodology incorporated a relative weighting of the peak day capacity savings and the seasonal gas cost savings produced by the Field. However, although the underlying premise of his proposed used and useful disallowance is that the Field is not performing at the design levels represented to the Commission when the investment in the expanded Field was placed into rate base, he failed to use the relative weighting of the Field's peak day capacity savings and seasonal gas cost savings presented in that rate case (Docket 93-0183). Instead, he used a weighting based on peak day capacity and seasonal gas cost savings that he calculated using data for the period 1999-2000 through 2003-2004. Use of the same relative weighting of the Field's peak day capacity savings and seasonal gas cost savings that was presented in Docket 93-0183, when the expanded Field was placed in rate base, shows Hillsboro to be 96.8% used and useful. (Rev. IP Ex. 13.1, pp. 14-15)

Finally, in an attempt to bolster his argument that the Commission should impose a used and useful disallowance for Hillsboro, Mr. Lounsberry, under the heading "Overall Storage Concerns", raised a number of additional concerns he has with IP's previous management of its gas storage fields. (Staff Ex. 7.0, pp. 31-53) Most of these items have been raised by Mr. Lounsberry in one or more previous dockets in support of a proposed disallowance, with no success on Mr. Lounsberry's part. All of them are unfounded, and, most importantly, none of them has any causal relationship to the reduced deliverability experienced at the Hillsboro Field or to its specific cause, the turbine injection metering error. Mr. Lounsberry's "Overall Storage Concerns" should all be rejected as providing no support to his proposed used and useful adjustment for the Hillsboro Field.

2. The Hillsboro Storage Field is Fully Used and Useful

Staff witness Lounsberry pointed out that two sections of the PUA provide the criteria for including plant in rate base as "used and useful". (Staff Ex. 7.0, p. 21) Section 9-211 (220 ILCS 5/9-211) states:

> The Commission, in any determination of rates or charges, shall include in a utility's rate base only the value of such investment which is both prudently incurred and used and useful in providing service to public utility customers.

Further, Section 9-212 of the PUA (220 ILCS 5/9-212) states:

> No new electric generating plant or gas production facility, or significant addition to existing facilities or plant, shall be included in a utility's rate base unless and until the utility proves, and the Commission determines, that such plant or facility is both prudent and used and useful in providing utility service to the utility's customers. . . A generation or production facility is used and useful only if, and only to the extent that, it is necessary to meet customer demand or economically beneficial in meeting such demand.

The record shows that in its current operating condition, the Hillsboro Storage Field satisfies these criteria. Although the peak deliverability rating of the Hillsboro Field was reduced from its "design" value of 125,000 mcf/day to 100,000 mcf per day prior to the 1999-2000 winter season, the rating was restored to 125,000 mcf/day prior to the 2003-2004 winter season, and this peak day deliverability rating was confirmed through a test on January 30, 2004. (Rev. IP Ex. 14.1, pp. 18-19) Mr. Lounsberry agreed that IP is presently operating its storage fields at their rated peak day capacities. (Staff Ex. 17.0R, p. 37) Further, for the 2004-2005 (i.e., the current) winter season, IP injected 4.6 bcf of working gas into the Hillsboro Field, and is prepared to withdraw 4.1 bcf of working gas during this winter season to supply to customers. (Rev. IP Ex. 13.1, pp. 7, 9, 11) At these capacities, Hillsboro is "necessary" to meet customer demand and "economically beneficial" in meeting customer demand.

Taking the "economically beneficial" criterion first, Illinois Power witness Kevin Shipp calculated that Hillsboro's 125,000 mcf/day of peak deliverability saves **BEGIN CONFIDENTIAL** XXX **END CONFIDENTIAL** million annually in pipeline FT charges and that cycling 4.1 bcf of gas (the amount being cycled in the 2004-2005 winter) will save **BEGIN CONFIDENTIAL** XXX **END CONFIDENTIAL** million as compared to 2004-2005 spot commodity gas prices.[31] Thus, the total annual cost savings (all of which would be reflected in the PGA charges to customers) from operating Hillsboro at its current operating parameters are **BEGIN CONFIDENTIAL** XXX **END CONFIDENTIAL** million.[32] (Rev. IP Ex. 13.1, pp. 16-17) In comparison, the annual revenue requirement for the Hillsboro Field, including operation and maintenance ("O&M") costs, depreciation and return on the full investment at the rate of return last proposed by the Staff rate of return witness in this case, 8.25%, is $7,257,000.[33] (Rev. IP Ex. 13.9, p. 4) Thus, at its current operating levels, the gas cost savings provided by the Hillsboro Field *substantially exceed* the revenue requirement associated with including Hillsboro in rate base as 100% used and useful. Clearly, the Hillsboro Storage Field is "economically beneficial" in meeting IP gas customers' service demands.

Moreover, even if Mr. Lounsberry's calculations of the savings produced by the Hillsboro Field were used in this comparison (which would be inappropriate, since his calculations are based on data that is up to five years old and do not reflect the current operating

[31]The calculation of pipeline FT savings assumes that pipeline firm transportation capacity into the region served by the Hillsboro Field could in fact be obtained to replace the entire deliverability of the Field. As discussed immediately below, it is far from certain that this amount of pipeline capacity is available in the current market.

[32]These calculations are described in greater detail in Section II.D.3 below.

[33]Per the Stipulation between IP and Staff, the stipulated rate of return on rate base to be used in calculating the revenue requirement in this case is 8.18%. Based on the final stipulated rate of return of 8.18%, the Hillsboro revenue requirement is even lower than $7,257,000.

parameters of the Field), the revenue requirement to include Hillsboro in rate base as 100% used and useful is *still* less than the annual gas cost savings produced by the Field. Mr. Lounsberry calculated that Hillsboro produces peak day capacity savings (based on an assumed peak day rating that is somewhat below 125,000 mcf/day) of **BEGIN CONFIDENTIAL** XXXXXXX **END CONFIDENTIAL** and that the Field produces seasonal gas cost savings of **BEGIN CONFIDENTIAL** XXXXXXX **END CONFIDENTIAL**, for total annual gas cost savings of **BEGIN CONFIDENTIAL** XXXXXXX **END CONFIDENTIAL**. (Rev. IP Ex. 13.9, p. 5) These annual gas cost savings produced by the Hillsboro Field *still exceed* the annual revenue requirement for including Hillsboro in rate base as 100% used and useful, which as noted above is something less than $7,257,000.

Mr. Lounsberry did not present an "economic benefits" test in this case of the form just described. Nor, after IP witness Kevin Shipp presented this "economic benefits" test in his rebuttal testimony, did Mr. Lounsberry even acknowledge its appropriateness in his own rebuttal testimony. For Mr. Lounsberry to fail to present an annual revenue requirements versus cost savings analysis of this type, or to acknowledge its appropriateness, was disingenuous in the extreme, because this is *exactly* the form of test that Mr. Lounsberry submitted to the Commission in a recent AmerenCIPS/AmerenUE rate case in which Mr. Lounsberry argued (successfully) that the Belle Gent storage field was no longer used and useful under Sections 9-211 and 9-212 of the PUA and should be retired. *See* Order in Dockets 02-0798, 03-008 & 03-009 (Cons.), October 22, 2003, pages 25-27.[34] As the Commission there stated in describing Staff's position:

[34]As stated at page 24 of that Order, Mr. Lounsberry was the Staff witness who recommended that the Belle Gent storage field was no longer used and useful and should be retired.

> The alternate prong of the "used and useful" test requires a utility facility to provide an economic benefit when meeting customer demand. Staff claims that the costs of Belle Gent substantially exceed the benefit ratepayers have received from the field over the past several years. In Staff's view, the storage field, therefore, does not provide an economic benefit to customers.
>
> For its analysis, Staff measures benefits against the annual revenue requirement calculated in this proceeding of over $67,000 for CIPS to continue operating the field. Staff also notes that over the past seven years, the only winter season in which the storage field operated was 2003. Staff asserts that Belle Gent produced a savings to ratepayers of $17,000 for its operations in 2003, and no benefit to rate payers in the other six years. Staff suggests that the real economic cost of operations during the entire period was the product of the annual revenue requirement ($67,000) and the period of years (7), for a total cost of $469,000. Staff compares this figure to a total economic benefit of $17,000 over the seven year period, and thereby concludes that the Belle Gent field also fails the "economically beneficial" prong of the "used and useful" test. (Order in Dockets 02-0798, 03-0008 & 03-0009 (Cons.), pp. 26-27)

In short, in the AmerenCIPS-AmerenUE case, Mr. Lounsberry testified that the way to determine if a storage field is used and useful is to analyze whether it is "economically beneficial" by comparing its annual revenue requirement to the cost savings it produces for customers. Yet in *this* case he failed to present such an analysis, and failed to acknowledge this analysis as appropriate when it was presented by IP.

The Hillsboro Storage Field is also "necessary to meet customer demand." At its current operating level (which, as discussed earlier, was in effect for the 2003-2004 winter season as well as the current winter season and was confirmed by a capacity test on January 30, 2004), the Hillsboro Field provides 125,000 mcf of peak day deliverability. The capacity of the Hillsboro Field serves the Metro East area and the Decatur area. (Rev. IP Ex. 3.19, p. 11) In terms of interstate pipelines, the Metro East area is served by Natural Gas Pipeline Company of America ("NGPL") and Mississippi River Transmission Corporation ("MRTC"), while the Decatur area is primarily served by Panhandle Eastern Pipe Line Company ("PEPL"), although it is also served by NGPL. (*Id.*) In the current market, PEPL is fully subscribed and at least one of the mainline legs of NGPL into Illinois is fully subscribed.[35] (*Id.*) Thus, there may not be sufficient available pipeline FT capacity on NGPL and PEPL to replace the entire 125,000 mcf/day of Hillsboro capacity. (Rev. IP Ex. 13.1, p. 13) In short, if the Hillsboro Field did not exist, it likely *would not be possible* to replace its peak deliverability capacity with pipeline FT.

Staff witness Lounsberry did not dispute the fact that it might not be possible to replace the entire capacity of the Hillsboro Field by purchasing additional FT capacity from the interstate pipelines serving the area. To the contrary, he admitted, "I do not know if there currently exists sufficient surplus pipeline capacity to replace the Hillsboro storage field." (Staff Ex. 17.0R, p. 32) Thus, the Hillsboro Storage Field meets the "necessary to meet customer demand" criterion for being fully used and useful – it provides necessary peak day capability to the IP gas system and its customers that may not be obtainable from other sources (i.e., the interstate pipelines). (Rev. IP Ex. 13.9, p. 14)

The foregoing discussion shows that the Hillsboro Storage Field is presently fully used and useful based on the statutory criteria of "necessary to meet customer demand" and "economically beneficial". For purposes of determining whether Hillsboro should be included in rate base in this case as 100% used and useful, this ought to be the end of the discussion. Nonetheless, we next proceed to a discussion of the flaws in Mr. Lounsberry's calculation by which he attempted to support his position that Hillsboro is only 53.44% used and useful.

3. Mr. Lounsberry's Calculation of the Hillsboro Used and Useful Percentage Is Flawed and Inappropriate

Mr. Lounsberry arrived at his position that the Hillsboro Field is only 53.44% used and useful through the following calculations: Citing three prior Illinois Power rate orders, he

[35]Further, most of IP's transmission capacity into Decatur from NGPL is utilized by retail transportation customers. (Rev. IP Ex. 13.9, p. 11)

concluded that a three-year average calculation should be used to determine the used and useful percentage, and he selected the years 2001-2002, 2002-2003 and 2003-2004. He calculated a peak day savings benefit provided by Hillsboro's 125,000 mcf/day of deliverability by pricing this amount of pipeline FT and gas supply reservation costs. Next, he calculated a seasonal gas cost savings benefit of Hillsboro's design 7.6 bcf working gas inventory by comparing IP's weighted average cost of gas in storage over the five winter seasons 1999-2000 through 2003-2004 to the weighted average price of commodity gas for the same years, calculating a per unit savings per month for this period, and applying the unit savings to the 7.6 bcf working gas inventory. He used the calculated peak deliverability and seasonal gas cost savings to calculate a weighting of the overall savings benefit of Hillsboro between peak day savings (36.79%) and seasonal gas costs (63.21%). Finally, he calculated the peak day rating at which Hillsboro operated as a percent of its design rating, and the actual working gas cycled as a percent of the 7.6 bcf design volume, over the three year period 2001-2002 through 2003-2004, applied the 36.79% and 63.21% weightings to these respective percentages, and summed the totals to get 53.44%, which he concluded should be Hillsboro's used and useful percentage for purposes of this case.[36] (Staff Ex. 7.0, pp. 26-30, and Schedules 7.04-7.07)

As the following subsections show, Mr. Lounsberry's calculation was flawed and inappropriate at virtually every step. Even using his basic methodology, which is itself inappropriate, Hillsboro should be calculated to be no less that 84.33% used and useful.

[36]In Mr. Lounsberry's direct testimony he actually calculated his used and useful percentage to be 53.94% due to a calculation error. In his rebuttal testimony he corrected this error to arrive at 53.44%. (Staff Ex. 17.0R, pp. 24-25)

a. <u>Use and Selection of Three-Year Period</u>

In his direct testimony, Mr. Lounsberry cited three prior Illinois Power rate cases in which the Commission used three year averages of IP's electric generating capacity and electric peak demand to calculate the used and useful percentage of Clinton Power Station. Those three cases were Dockets 84-0055, 87-0695 & 88-0256 (cons.) (March 30, 1989) ("Docket 84-0055"), pp. 146-147; Docket 89-0276 (June 6, 1990), pp. 78-82; and Docket 91-0147 (Feb. 11, 1992), p. 15. (Staff Ex. 7.0, pp. 29-30) Purportedly based on these three orders, he elected to use the three years 2001-2002, 2002-2003 and 2003-2004 in his analysis.

At the outset the Commission should question whether using three-year averages is appropriate for purposes of this case and whether instead only the most current information, representing the operating condition of Hillsboro and gas market conditions and prices immediately prior to the rates set in this case going into effect, should be used for any used and useful calculations. In Section II.D.2 above, the Company presented a calculation of the annual gas cost savings currently (i.e., 2004-2005 winter) being provided by the Hillsboro Field. However, the purpose of this section of this Brief is to identify the flaws in Mr. Lounsberry's used and useful calculation as he applied it. With that premise in mind, a review of the Commission's prior orders shows that Mr. Lounsberry's calculation should use the three-year period 2003-2004, 2004-2005 and 2005-2006.

In Docket 84-0055, for which the test year was 1986 and the order was issued in March 1989, the Commission used the three years 1988, 1989 and 1990 in its used and useful calculation. In Docket 89-0276, for which the test year was 1990 and the order was issued in June 1990, the Commission used the three years 1989, 1990 and 1991. In Docket 91-0147, in which the test year was 1992 and the order was issued in February 1992, the Commission looked at several three-year periods in making its used and useful determination: 1991-1993, 1992-1994 and 1993-1995. A consistent thread among these three cases is that the three-year period the Commission used consisted of the year prior to the year of the order, the year in which the order was issued (i.e., the year in which the new rates went into effect) and the year following the order. Applying the same approach to the circumstances of this case, the three years that should be used are 2003-2004, 2004-2005 (2005 being the year the new rates go into effect) and 2005-2006. (Rev. IP Ex. 13.1, p. 10) Certainly, in none of the three cases relied on by Mr. Lounsberry did the Commission use a three-year period that completely preceded the order date, as Mr. Lounsberry has done here.[37]

In his rebuttal testimony, Mr. Lounsberry stated "I agree that generally the Commission dealt with the used and useful issue for the Clinton nuclear plant using the three-year period discussed by [IP witness] Mr. Shipp", but he then cited another prior Commission order, *Commonwealth Edison Company*, Docket Nos. 87-0427/87-0169/88-0219/88-0253/90-0169 (cons.), Revised Order on Remand (Feb. 24, 1993) ("*ComEd*"), in which, he asserted, "the Commission made use of a three-year period that centered on the test year." (Staff Ex. 17.0R, p. 28) Despite Mr. Lounsberry's efforts in his rebuttal to back away from the authorities he himself relied on his direct testimony, review of *ComEd* shows that in that case the Commission also essentially used a three-year period consisting of the year before the order, the year of the order and the year after the order.[38]

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[37]Moreover, in the three prior cases <u>all</u> of the data the Commission used was <u>projected</u>. In <u>none</u> of these cases did the Commission use three years of completely historic data – not even in Docket 84-0055, which used an historic 1986 test year for overall revenue requirement purposes – as Mr. Lounsberry has done here.

[38]As shown above, in Docket 84-0055, which was the only one of the four cases cited by Mr. Lounsberry that used an historic test year, the Commission did *not* use a three-year period "centered on the test year" for its used and useful analysis.

Although *ComEd* comprised a number of dockets that had been consolidated, the used and useful determination was made in the context of a rate case, Docket 90-0169, that had been originally filed in April 1990. (*ComEd* Order, p. 4) The original order was issued on March 8, 1991, and used a 1991 test year. (*Id.*, pp. 1, 4) In an appeal by intervenors from the March 8, 1991 Order, the Supreme Court ruled that the Commission had misapprehended the meaning of Section 9-215 of the PUA (a statute applicable only to electric generating plants) in determining what used and useful test it could apply to certain of the utility's generating plants.[39] The case was therefore remanded to the Commission to reconsider its used and useful determination. On remand, consistent with the Supreme Court decision, the Commission used a three-year load and capacity analysis (as it had in the three Illinois Power cases). However, the Commission recognized that it could not update the original record for more recent information but rather had to use the load and capacity data in the original record, which was for the three years 1990, 1991 and 1992. (*ComEd* Order, p. 4) Thus, in the *ComEd* Order, although it was issued in 1993, the Commission essentially "redid" the used and useful analysis in its original 1991 order using data from the year before the order, the year of the order and the year following the order. Again, in the context of this case, this approach supports using the three-year period 2003-2004, 2004-2005 and 2005-2006, *not* three completely historic years as employed by Mr. Lounsberry.

In any event, in a subsequent order issued after the four orders relied on by Mr. Lounsberry, the Commission addressed precisely the issue of which three-year period to use in a used and useful analysis, and adopted the position advocated here by IP while rejecting the position advocated by Mr. Lounsberry. *Commonwealth Edison Company*, Docket 94-0065 (Jan.

[39] *Business & Professional People for the Public Interest v. Commerce Commission*, 146 Ill. 2d 175 (1991). In its original March 1991 order, the Commission had not used a three-year load and capacity analysis in making its used and useful determination.

9, 1995), 158 P.U.R. 4th 458, 1995 WL 45969. In resolving a disputed issue as to which three-year period to use for the used and useful test, the Commission stated:

> While the remaining parties are in agreement on the used and useful methodology, there is substantial disagreement with respect to the various components of the needs test. The first issue on which they disagree is the period during which the units' used and useful status is determined. Edison proposes a three-year period of 1994-1996, centered on the year rates will take effect; Staff and CUB propose a three-year test period of 1993-1995 centered on the test year; and the City proposes use of the test year only. In the Remand Order the Commission indicated its preference for a three-year period rather than the one-year test year for the needs determination. **All five of the Commission's past decisions establishing three-year used and useful periods centered their used and useful periods on a year in which the rates to be charged were to be in effect. The Commission has not required that the three year period be centered on the test year.** See Illinois Power Company, Docket 84-0055 et al., p. 146. The Commission continues to believe that the three-year averaging process is appropriate, and finds that **Edison's proposed 1994-1996 period, which is centered on the year the rates determined in this proceeding will take effect, is the appropriate test period and is consistent with past decisions of the Commission.** The Commission believes it is reasonable to employ a used and useful test period that provides a more prospective view of whether Byron Unit 2 and Braidwood Units 1 and 2 are used and useful. (emphasis supplied)

Clearly, the Commission's resolution of this issue in Docket 94-0065 – in which it took into account the prior orders relied on here by Mr. Lounsberry – requires that the three-year period he advocates be rejected and that the three-year period that IP employed in its re-do of Mr. Lounsberry's calculations should be adopted. Mr. Lounsberry's three-year period centers on the historic test year while the three-year period used by IP witness Mr. Shipp centers on the year the rates approved in this case will go into effect, i.e., the year of the rate order.

The decision as to which three-year period to use in this case is not merely an academic exercise. In two of the three years Mr. Lounsberry used, Hillsboro was rated at 100,000 mcf/day peak deliverability, whereas in each of the three years 2003-2004, 2004-2005 and 2005-2006, Hillsboro is rated at its full 125,000 mcf/day peak deliverability (which Mr. Lounsberry agreed is the rating at which Hillsboro is now operating). Thus, Mr. Lounsberry's selection of a three-year period results in a lower used and useful percentage in his calculation. In any event, regardless of the period selected for the calculations, a peak deliverability rating of 125,000 mcf/day should be used in the used and useful calculation, since the rating of the Hillsboro Field was restored to that value prior to the 2003-2004 winter season and the 125,000 mcf/day rating has been confirmed by testing. (Rev. IP Ex. 13.1, p. 11)

With respect to the seasonal gas cost calculation, the annual average amount of gas cycled from the Field in the three-year period selected by Mr. Lounsberry is lower than the annual average amount of gas cycled or to be cycled in 2003-2004, 2004-2005 and 2005-2006. (Compare Staff Schedule 7.04 to Rev. IP Ex. 13.1, p. 11) Here again, Mr. Lounsberry's selection of an inappropriate three-year period drove down his calculated used and useful percentage.

Accordingly, to the extent the Commission relies on Mr. Lounsberry's three-year approach at all, it should use the three years 2003-2004, 2004-2005 and 2005-2006 for the used and useful calculation.

b. Value of Replacement Pipeline FT Capacity in Peak Capacity Cost Savings Calculation

In calculating the peak day capacity cost savings benefit produced by Hillsboro, Mr. Lounsberry used a price taken from just one of IP's current pipeline FT contracts for the cost of replacement pipeline FT capacity. Specifically, he used the rate in IP's contract associated with the NGPL Metro East Lateral.[40] (Rev. IP Ex. 13.1, p. 12) This selection was flawed in several respects.

[40]He obtained the FT price he used from IP's response to a data request in its PGA reconciliation case for 2003, Docket 03-0699. (See Staff Ex. 7.0, p. 27 and Schedule 7.05)

First, Mr. Lounsberry's use of a single FT rate from a single year (2003) was inconsistent with his own approach of using a three-year average for his used and useful calculations. It was also inconsistent with his use of five years of historical data to calculate the seasonal gas cost savings. Given Mr. Lounsberry's statement in his testimony that the cost of peak day transportation capacity has been declining over time (Staff Ex. 17.0R, p. 35), his internally inconsistent use of just a single, recent pipeline FT rate appears to be directed at driving down the value of Hillsboro's peak deliverability.[41]

Second, and more significantly, the FT price Mr. Lounsberry elected to use was for transportation on an NGPL lateral that runs *only from Centralia, Illinois to the Metro East area*, entirely within the IP service area. It is not a long-haul contract and does not include the cost of firm pipeline transportation from the gas producing fields to the IP service area. It falls far short of representing the full cost to replace Hillsboro's peak day capacity with pipeline FT. (Rev. IP Ex. 13.9, p. 10) In contrast, the pipeline FT costs that IP witness Shipp used in re-doing Mr. Lounsberry's calculations were representative of the full costs of pipeline FT from the gas producing fields in the Mid-continent area (Texas-Oklahoma-Kansas) and the Gulf Coast area (Texas-Louisiana) to IP's service area. (*Id.*) Not surprisingly, therefore, the pipeline FT costs that Mr. Shipp used, and the resultant peak day capacity cost savings benefit he calculated, were

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[41]Hillsboro's expected peak deliverability was reduced for several years, but only to 80% of its design value (i.e., 100,000 mcf/day vs. 125,000 mcf/day). In contrast, in the three years selected by Mr. Lounsberry only about 34% to 36% of the maximum working gas inventory of 7.6 bcf was cycled. (Staff Sched. 7.04) Under the methodology he employed, by driving down the value of Hillsboro's peak deliverability savings benefit relative to the seasonal gas cost savings, Mr. Lounsberry could calculate a lower "weighting" for the peak capacity benefit (an area in which Hillsboro has performed closer to its design value) and a greater weighting for Hillsboro's seasonal gas savings benefit (an area in which Hillsboro's performance has been farther from its design value), thereby producing a lower overall used and useful percentage. Mr. Lounsberry's selection of the pipeline FT price he used enabled him to calculate a low used and useful percentage for Hillsboro.

considerably higher than those calculated by Mr. Lounsberry. The peak day capacity cost savings benefit that Mr. Shipp calculated, using complete pipeline FT costs, exceeded the peak day capacity cost savings benefit that Mr. Lounsberry calculated by more than 2.5 times. (See Rev. IP Ex. 13.1, p. 12)

Third, even putting aside Mr. Lounsberry's use of the FT price for an NGPL lateral that runs only within IP's service area, Mr. Lounsberry failed to recognize that (as discussed earlier), the Hillsboro Field serves two distinct areas, the Metro East area and the Decatur area, which are served principally by different interstate pipelines (NGPL and PEPL, respectively). (Rev. IP Ex. 13.1, p. 12, Rev. IP Ex. 13.9, p. 11) It would not be possible to replace all of the capacity of the Hillsboro Field with NGPL capacity (assuming that much capacity were in fact available on NGPL) and still serve the geographic areas of IP's service area that are served using the peak day capability of the Hillsboro Field. (Rev. IP Ex. 13.9, p. 11) Thus, to replace Hillsboro's capacity would necessitate the acquisition of additional FT capacity on both NGPL and PEPL.[42] In contrast to Mr. Lounsberry, Mr. Shipp, in re-doing Mr. Lounsberry's used and useful calculations, used an average of the prices from IP's most recent FT contracts negotiated with NGPL and PEPL.[43] (Rev. IP Ex. 13.1, p. 12)

Finally, Mr. Lounsberry erroneously asserted that if IP were to replace the entire capacity of the Hillsboro Field with pipeline FT, IP should be able to obtain greater discounts from the

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[42]Although NGPL also serves the Decatur area, virtually all of IP's transmission capacity into the Decatur area from NGPL is already used by transportation customers. (Rev. IP Ex. 13.9, p. 11)

[43]The amount of these contracts aggregated to approximately the amount of FT capacity that would be needed to replace Hillsboro's peak day capacity. (Rev. IP Ex. 13.9, p. 12)

prices it currently pays for pipeline FT capacity.[44] (Staff Ex. 17.0R, p. 31) His contention displayed a lack of appreciation of current market realities. As noted earlier, PEPL is fully subscribed and at least one of the NGPL mainline legs into Illinois is fully subscribed. As a result, these pipelines basically have no reason to give significant discounts in order to sell large blocks of incremental FT capacity (i.e., capacity above and beyond the historic capacity levels already held by IP) under current capacity market conditions. In light of the existing pipeline capacity markets in the Midwest, IP would expect to pay *higher* prices, not lower prices, for large blocks of incremental FT capacity.[45] (Rev. IP Ex. 13.9, p. 12)

c. <u>Seasonal Gas Cost Savings</u>

To calculate the seasonal gas cost savings benefit of Hillsboro (i.e., the reduced gas costs that can be achieved by buying gas in the summer months, injecting it into storage and then withdrawing it in winter months to serve customers rather than purchasing spot commodity gas during the winter), Mr. Lounsberry used the difference between IP's cost of gas in storage and the cost of spot gas purchased by IP over the five year historical period 1999-2000 through 2003-

[44]Once again, an assumption of a lower pipeline FT replacement price would enable Mr. Lounsberry to assign a lower relative weighting to the peak capacity savings benefit of Hillsboro and thereby generate a lower used and useful percentage.

[45]Mr. Lounsberry asserted that his position that IP could achieve larger discounts if purchasing large blocks of incremental FT capacity was supported by testimony of an Ameren witness in Docket 04-0294 concerning "buying power" savings in IP's purchased gas costs as a result of the Ameren acquisition. (Staff Ex. 17.0R, p. 31) Mr. Lounsberry cited that testimony out of context. While the Ameren witness testified that IP should be able to get larger discounts in the future negotiating as part of Ameren than it could have obtained standing alone, he did *not* testify that IP would be able to obtain larger discounts in the future as a part of Ameren than IP had obtained in the past as a stand-alone company under significantly different market conditions. The Ameren witness made it clear that future pipeline discount levels will vary over time based on market conditions. (Rev. IP Ex. 13.9, p. 13)

2004.[46] (Staff Ex. 7.0, pp. 27-28) His use of five years of historic data was flawed. Indeed, Mr. Lounsberry himself emphasized that gas markets are not static and that "many changes have occurred over the past ten years." (Staff Ex. 17.0R, p. 35) As Mr. Shipp stated:

> To accept Mr. Lounsberry's calculation of the seasonal gas cost savings to be expected from the Hillsboro Field, the Commission would have to assume that Illinois Power bought gas for injection during the 2004 injection season at the same prices it purchased gas for injection in 1999, 2000 and 2001, and that it will be able to buy spot commodity gas during the 2004-2005 winter at the same prices for which gas was purchased in the 1999-2000, 2000-2001 and 2001-2002 winter seasons. . .
>
> Over the period that Mr. Lounsberry used for his seasonal gas cost savings calculation, the gas markets have in fact changed significantly. Due to the relatively recent installation of almost 200,000 mW of gas-fired electric generation in the U.S. which has increased the demand for gas during the summer, there are now periods in which gas prices in the winter heating season are not significantly different than prices in the summer. In fact, at times during the summer injection season, commodity gas prices can be higher than in the winter season. The realities of recent and current market pricing are not reflected in the five-year historical data used by Mr. Lounsberry. (Rev. IP Ex. 13.9, p. 9)[47]

Mr. Shipp explained that the appropriate comparison to calculate Hillsboro's seasonal gas cost savings benefit would be to compare the cost of gas when it is injected into the Field to the spot price of gas at the time of withdrawal, utilizing futures prices, not historical prices. In re-doing Mr. Lounsberry's calculations, Mr. Shipp used a comparison between New York Mercantile Exchange ("NYMEX") prices for (i) gas deliveries in the April 2005 to October 2005 period and (ii) gas deliveries in the November 2005 to March 2006 period. (Rev. IP Ex. 13.1,

[46]Mr. Lounsberry's use of a five-year period to develop the seasonal gas cost savings benefit was inconsistent with his use of a three-year period for the overall used and useful analysis. (Rev. IP Ex. 13.9, p. 15)

[47]Here again, Mr. Lounsberry's use of five years of historical data rather than current market pricing to develop the seasonal gas cost savings appears to have been results-driven. Under his methodology, by calculating a higher seasonal gas cost savings benefit for Hillsboro, Mr. Lounsberry could then calculate a higher weighting for the seasonal gas cost benefit relative to the peak day capacity benefit, and thereby produce a lower used and useful percentage.

pp. 13-14) He stated that the futures prices he used in re-doing Mr. Lounsberry's calculations are prices quoted on the NYMEX for contracts for delivery of gas in those months. (Rev. IP Ex. 13.9, p. 15)

Current gas futures prices on the NYMEX are a much more reliable indicator of spot commodity gas prices since they represent actual commodity price positions taken by market participants based upon current gas market fundamentals. (Rev. IP Ex. 13.9, p. 9) The NYMEX gas futures market is recognized as the primary tool for price discovery by the entire gas industry. Unlike the five-year-old data used by Staff witness Lounsberry, the NYMEX contracts are actual price positions based upon current and future market conditions and industry fundamentals. The NYMEX is the most accurate representation of future price differentials under current market conditions between gas commodity purchased during the summer injection season and gas purchased during the winter heating season, which is the basis of the seasonal gas cost savings provided by storage fields. (*Id.*, pp. 15-16) Consistent with the proposition that the determination of whether the Hillsboro Field is used and useful for the purpose of setting rates that will go into effect in May 2005 and be in force thereafter should be based on the current and reasonably foreseeable operating status of the Field, NYMEX gas futures prices, rather than five-year old price data, should be used to calculate the seasonal gas cost savings benefit that Hillsboro produces.

There is yet another problematic aspect of the seasonal gas cost portion of Mr. Lounsberry's used and useful calculation. In calculating the Hillsboro used and useful percentage, Mr. Lounsberry took the amount of gas cycled in each of the three years 2001-2002 through 2003-2004 as a percent of 7.6 bcf, the maximum "design" working gas inventory of the Field. (See Staff Schedule 7.04) His approach assumes that the entire 7.6 bcf working gas inventory should be withdrawn from the Field each winter season to be supplied to customers. This is an unrealistic assumption – the entire amount of working gas inventory in a storage field will not necessarily be withdrawn in every year. IP would expect to cycle the full inventory of working gas in its fields each winter season assuming normal weather and no other abnormal changes in load. However, if winter weather is warmer than normal or there is an unexpected drop in load (particularly in the second half of the withdrawal season), the full working gas inventory may not be withdrawn. In addition, storage fields can experience temporary fluctuations in the amount of working gas that can be cycled, due to operational issues that arise as a result of the nature of storage field operations. Therefore, it is not realistic to assume that the entire working gas inventory of a particular storage field would be cycled every year.[48] (Rev. IP Ex. 13.1, p. 8)

The Commission should keep the foregoing point in mind in considering Mr. Lounsberry's used and useful calculations as well as the re-calculations of Mr. Lounsberry's analysis performed by IP witness Mr. Shipp, which produced used and useful percentages ranging from 84% to 97% (see Sections II.D.3.d and e below for development of these percentages). As is obvious from a cursory examination of Mr. Lounsberry's schedules (see, e.g., Staff Schedule 17.01), under Mr. Lounsberry's methodology Hillsboro would have to be rated at its full peak deliverability capacity of 125,000 mcf/day *and* cycle its maximum design capacity of 7.6 bcf in *each year* of the three-year period in order for his methodology to show the Field to be 100% used and useful. Thus, for example, under Mr. Lounsberry's methodology, even if the amount of working gas cycled from Hillsboro were consistently 95% of the maximum of 7.6 bcf (whether due to warmer weather, load fluctuations or other reasons), his calculations

[48] Mr. Lounsberry did not dispute any of the foregoing discussion as presented in the testimony of IP witness Kevin Shipp.

would show Hillsboro to be less than 100% used and useful. In short, Mr. Lounsberry's methodology requires perfection in order for Hillsboro to be 100% used and useful. IP is unaware that this Commission has heretofore required perfection from Illinois gas utilities in the operation of their storage fields.[49] Mr. Lounsberry's used and useful "test" is unreasonably stringent and inconsistent with operating realities, and should be rejected.

d. Recalculation of Mr. Lounsberry's Analysis

Illinois Power witness Mr. Shipp recalculated the Hillsboro used and useful percentage using Mr. Lounsberry's methodology but (i) using the three years 2003-2004, 2004-2005 and 2005-2006 rather than the earlier three year period used by Mr. Lounsberry; (ii) using the full 125,000 mcf/day peak deliverability rating of Hillsboro for each of the three years (which in fact was the case), (iii) using as the replacement pipeline FT price the average of the prices paid to NGPL and PEPL in IP's most recently negotiated contracts with these pipelines, and (iv) using NYMEX futures contracts prices for the summer injection and winter withdrawal seasons to develop the seasonal price differential, rather than historical prices that were as much as five years old, as employed by Mr. Lounsberry. Using these parameters and inputs, Mr. Shipp calculated an 84.33% used and useful percentage for Hillsboro, in contrast to the 54.33% used and useful percentage that Mr. Lounsberry had calculated. (Rev. IP Ex. 13.1, p. 14)

It is noteworthy that Mr. Shipp's calculations generated a weighting for the peak day savings benefit of 66.24% and a weighting for the seasonal gas cost savings benefit of 33.76% (*Id.*), which was almost the complete reverse of the respective weightings (35.83% and 64.17%) generated by Mr. Lounsberry. (See Staff Sched. 17.01) With the higher relative weighting for the peak day savings benefit and the better relative performance by the Hillsboro Field with

[49] In fact, as the Commission recently recognized in Docket 01-0701, "a natural gas aquifer storage field is a complex physical system." (Order, Docket 01-0701 (Feb. 19, 2004), p. 25)

respect to peak day deliverability as opposed to annual working gas inventory cycling, Mr. Shipp calculated a used and useful percentage considerably higher than the percentage Staff witness Lounsberry calculated. This demonstrates how though his choices of the three-year period, the price of replacement FT capacity and the five-year historic gas prices he used, Mr. Lounsberry generated an inaccurately low used and useful percentage. Mr. Shipp's inputs and resulting calculations are much more representative of the current and foreseeable operating status of the Hillsboro Storage Field and of the industry and market conditions in which it will be operating when the rates established in this proceeding go into effect.

e. Used and Useful Calculation Employing Weightings of the Peak Day and Seasonal Gas Cost Savings Benefits Based on the Relative Benefits Expected from the Hillsboro Field in Docket 93-0183

As discussed above, Staff witness Lounsberry's used and useful calculations incorporated a relative weighting of peak day savings benefits and seasonal gas cost savings produced by the Hillsboro Field that reflected current (or at least, more recent) pipeline FT prices and commodity gas prices. However, in Docket 93-0183, the rate case in which the investment in the expanded Hillsboro Field was placed in rate base, IP presented a calculation of the value of the peak day savings benefits and seasonal gas cost savings benefits expected from the expanded Field. The entire premise for Staff witness Lounsberry's proposed used and useful adjustment was that the expanded Hillsboro Field has not provided the peak day deliverability and annual working gas volume that was planned when the investment in the expanded Field was placed in rate base in Docket 93-0183. Therefore, consistent with his underlying rationale, his calculation of whether and to what extent Hillsboro is used and useful calculation should have been based on the relative weightings of the peak day savings and seasonal gas cost savings benefits as presented to the Commission in Docket 93-0183. (Rev. IP Ex. 13.1, p. 14-15; Rev. IP Ex. 13.9, p. 3)

As quoted by Mr. Lounsberry, in Docket 93-0183 IP represented to the Commission that the expanded Hillsboro Field was projected to produce annual savings of $13,599,000 in reduced pipeline charges and $997,500 due to increased seasonal gas purchases. (Staff Ex. 7.0, p. 26, quoting Order in Docket 93-0183, p. 26) Thus, 93% of the savings from the Hillsboro expansion were from the Field's increased peak day deliverability while 7% of the savings were from increased seasonal gas purchases. If these percentages are inserted into Mr. Lounsberry's used and useful calculation at lines 9 and 10 of his Schedule 7.04, *with no other changes to his calculations*, the result of his calculations would be that Hillsboro is 85% used and useful, not 53% as calculated by Mr. Lounsberry. Further, if the calculations were based on the three-year period 2003-2004 through 2005-2006 (as Commission precedent indicates they should be), meaning that 125,000 mcf/day is used as the Field's actual peak day capacity for all three years and the amount of gas cycled on average for the three years is 53.58% of the 7.6 bcf maximum, then Mr. Lounsberry's calculations would show Hillsboro to be 96.8% used and useful. (Rev. IP Ex. 13.1, p. 15)

As shown in Section II.D.3.d above, Illinois Power's recalculation of Mr. Lounsberry's used and useful analysis resulted in a weighting of the cost savings benefits of 66.24% for the peak deliverability benefit and 33.76% for the seasonal gas cost savings benefit, which was almost the complete reverse of the respective weightings (35.83% and 64.17%) generated by Mr. Lounsberry. This shows that IP's corrected version of Mr. Lounsberry's calculations are actually much more representative of the original projected cost savings benefits from the expanded Field than was Mr. Lounsberry's original analysis.

The comparison of Mr. Lounsberry's weighting of the Hillsboro benefits to the weighting of the benefits indicated in Docket 93-0183 shows something else about Mr. Lounsberry's methodology: it is not simply measuring the impact of Hillsboro's below-design level performance during the years he analyzed, but *it is also measuring changes in the overall economics of the gas and pipeline markets subsequent to 1993*. As Mr. Lounsberry himself testified, "it is obvious that many changes have occurred [in the natural gas industry] over the last ten years, including the apparent reduction to the cost of peak day transportation capacity."[50] (Staff Ex. 17.0R, p. 35) One could envision a scenario, for example, in which the price of pipeline capacity has declined so much, and/or the price difference between summer and winter gas commodity prices has declined so much, since 1993, that Hillsboro could no longer be shown to be "economically beneficial".[51] Mr. Lounsberry has not suggested that Hillsboro should be declared less than 100% used and useful due to such an external industry trend – yet that in fact, at least in part, is what his used and useful calculation methodology is measuring. This is yet another reason why Mr. Lounsberry's used and useful calculations, and his overall used and useful disallowance recommendation, should be rejected by the Commission.

4. Mr. Lounsberry's "Overall Storage Concerns" Provide No Support for his Proposed Used and Useful Adjustment

a. Overview

In addition to his specific used and useful calculation which has been dissected in Section II.D.3 above, Mr. Lounsberry, in a further effort to justify his proposed used and useful disallowance for the Hillsboro Field, testified to a list of "overall storage concerns" regarding IP's overall management of its storage fields. His "overall concerns" relate to such things as (in

[50] As discussed earlier this brief, however, under current market conditions it is unlikely that IP could acquire sufficient incremental pipeline FT capacity to completely replace the peak day deliverability of the Hillsboro Field.

[51] As shown in Section II.D.2 of this brief, above, Hillsboro at this time continues to be economically beneficial in meeting customer demand, by a wide margin.

Mr. Lounsberry's view) inadequate root cause analysis, inadequate staffing at the storage fields and insufficient capital expenditures on the storage fields. (Staff Ex. 7.0, pp. 31-54; Staff Ex. 17.0R, pp. 35-51) The Commission should reject Mr. Lounsberry's contention that these "overall storage concerns" provide any support for his proposed used and useful adjustment to the Hillsboro Field. As discussed in Sections II.A and II.B, above, the deliverability decline at the Hillsboro Storage Field was caused by a measurement error in the plant injection meters which resulted in IP injecting less gas into the Field than it believed it was injecting based on the plant meter readings. Further, as shown in Section II.B above, Illinois Power was extremely proactive, worked diligently over a period of years, pursued several avenues of investigation and expended considerable resources, in attempting to find the cause of the deliverability declines. (Rev. IP Ex. 13.1, p. 19; see Rev. IP Ex. 14.1, pp. 4-16) Mr. Lounsberry has failed to show any connection between any of his "overall storage concerns" and the deliverability decline at the Hillsboro Field, and in fact there is no such connection. (Rev. IP Ex. 13.9, pp. 16-17)

Moreover, Mr. Lounsberry has previously raised a number of these same issues, including those he discussed in his testimony here under the headings "Reductions in Peak Day Capacity", "Manpower", "Capital Expenditures" and "Hillsboro Incident" in at least one and in some cases two previous annual PGA reconciliation cases before the Commission. IP has responded to these issues through discovery responses and testimony filed in those cases. In one of those cases, Docket 01-0701 (the PGA reconciliation case for 2001), Mr. Lounsberry cited a number of these issues as support for a proposed gas cost imprudence disallowance. However, the Commission (as well as the Administrative Law Judge) in that case rejected Mr. Lounsberry's recommendations and did not impose any imprudence disallowance based on any of these issues.[52] (Rev. IP Ex. 13.1, pp. 17-18) While the issue in *this* case is "used and useful", not prudence, it is nonetheless instructive that the Commission has previously been presented with these same "concerns" by Mr. Lounsberry in support of a proposed disallowance against IP, and has not found them sufficient to support imposition of a disallowance.

Below, Illinois Power responds briefly to Mr. Lounsberry's various "overall storage concerns."

b. <u>Reduction in Peak Day Capacity</u>

One of Mr. Lounsberry's "overall storage concerns" was that in recent years, IP has reduced the peak deliverability ratings on two of its storage fields, Hillsboro and Shanghai, which he contended was unusual and indicative of a problem with these fields. (Staff Ex. 7.0, pp. 32-34) He also acknowledged, however, that "IP, at the present time, is operating its storage fields at their rated peak day capacities."[53] (Staff Ex. 17.0R, p. 37) In any event, the used and useful status of Hillsboro is what is at issue in this case, so including the Hillsboro peak deliverability rating reduction (which has now been restored) in Mr. Lounsberry's "overall storage concerns" begs the ultimate issue in this case. With respect to the reduction in the peak deliverability rating of the Shanghai Field, Mr. Lounsberry recommended a gas cost

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[52]In the next year's (2002) PGA reconciliation case, Mr. Lounsberry was again the Staff witness but raised no imprudence or management issues. (See Order in Docket 02-0721 (July 21, 2004), p. 7) Interestingly, although the Hillsboro Field's peak day deliverability was reduced from 125,000 mcf/day to 100,000 mcf/day prior to the 1999-2000 winter season, and the amount of gas cycled from Hillsboro was considerably below its 7.6 bcf design maximum in a number of years from 1995-1996 through 2001-2002, neither Mr. Lounsberry (who has been the Staff witness on gas procurement issues in IP's PGA cases for many of those years) nor any other Staff witness has ever proposed a gas cost disallowance due to Hillsboro's reduced deliverability in any of the PGA reconciliation cases for these years.

[53]The Shanghai Field was de-rated for only one winter season, 2001-2002, before being restored to its original rating for the 2002-2003 winter, which it has maintained thereafter. (Rev. IP Ex. 13.1, pp. 21-22)

disallowance due to the Shanghai rating reduction in Docket 01-0701 (IP's 2001 PGA reconciliation case), but the Commission reached the following conclusion after considering all of Mr. Lounsberry's arguments and the Company's response:

> In light of the foregoing, the Commission is persuaded by IP that IP acted reasonably and prudently with regard to its decision to reduce the peak day deliverability of Shanghai by 25,000 Mcf/d for purposes of its 2001 PGA reconciliation. While certain errors occurred and hindsight shows that some of IP's observations and beliefs were incorrect, a natural gas aquifer storage field is a complex physical system and the Commission finds that under the circumstances IP's actions with respect to Shanghai were not imprudent. (Order, Docket 01-0701 (Feb. 19, 2004), p. 25))

Moreover, deliverability decline has been reported to be the most common problem in the gas storage industry. As Mr. Hower testified, U.S. Department of Energy publications indicate, based on more than 350 U.S. storage reservoirs, that most gas storage operators experience a decline in deliverability over time. As he stated, "This does not sound like an isolated problem, or one common only to Illinois Power. . . [Mr. Lounsberry's] observations regarding reductions in peak day capacity and declines in deliverability for gas storage reservoirs are not at all consistent with the experience of the overall gas storage industry." (IP Ex. 17.1, pp. 18-19) In fact, in his rebuttal testimony, Mr. Lounsberry stated, "I also agree with Mr. Hower that storage well and field deliverability declines are not uncommon in the industry." (Staff Ex. 17.0R, p. 37)

c. <u>Manpower</u>

A second of Mr. Lounsberry's "overall storage concerns" was that over the period from 1991 to 2000, IP reduced the number of supervisors at its storage fields from four to one. (Staff Ex. 7.0, pp. 34-36) (He acknowledged, however, that "the number of storage field *operators* has *remained stable* since 1991." *Id*., p. 35 (emphasis supplied)) IP witness Mr. Shipp explained how IP reorganized its work force in a manner that permitted the reduction in storage field supervisors. He noted that while reducing the number of supervisors, IP also upgraded one of the operator positions at each storage field to foreman. He pointed out that the storage field operators have more than 240 years of total gas storage experience and continue to increase their level of expertise through various training and educational programs. He further noted that IP also has a manager of storage who oversees all of the storage fields. (IP Ex. 13.1, pp. 20-21)

Mr. Lounsberry made the bald assertion that the reduction in number of supervisors has resulted in IP conducting poor root cause analysis (an assertion that IP also disputes), but he failed to support his assertion with any specifics. (Staff Ex. 7.0, p. 35) More importantly, he showed no connection between the Hillsboro deliverability decline and the reduction in the number of IP storage field supervisors. Moreover, his concern displayed no cognizance that IP also maintains a "headquarters" staff of engineering personnel (such as Mr. Hood and Mr. Kemppainen) who are engaged in the investigation of issues such as the Hillsboro deliverability decline; and that IP obtains outside resources (such as Mr. Hower and his firm) when needed to assist in such investigations and analyses. As Mr. Hood and Mr. Kemppainen testified:

> We have been involved in the investigation, discovery and remediation of the specific problem that led to the temporarily reduced capacity at the Hillsboro Storage Field that is the basis for Mr. Lounsberry's proposed used and useful adjustment, namely, the error in the turbine injection metering due to the operation of the compressors at certain loadings. Based on our involvement, we do not believe there is any connection between the reduction in the number of storage field supervisors and this problem or the time it took to discover the problem. Nor has Mr. Lounsberry identified any linkage. To the contrary, as we and Mr. Hower detailed in our rebuttal testimonies, Illinois Power diligently investigated the source of the declining performance at the Hillsboro Field over a number of years until it identified and corrected the problem. These efforts were not hampered by a lack of supervisory resources or a lack of any other resources. Similarly, there is no causal connection to support Mr. Lounsberry's assertion in the "Conclusion" to the "Overall Storage Concerns" section of his rebuttal testimony (lines 1011-1012) that "After reducing its manpower levels, IP's ability to identify and act upon problems at its storage fields declined." (IP Ex. 14.3, pp. 13-14)

d. Capital Expenditures

Another of Mr. Lounsberry's "overall storage concerns" was that IP's budgeted capital expenditures for its storage fields were lower in recent years (2002-2004) than in earlier years (2000-2001), that he was concerned that IP was not being proactive in making upgrades to its storage fields, and that IP was unwilling to make capital expenditures since the costs are not recoverable through the PGA.[54] (Staff Ex. 7.0, pp. 36-38)

However, Mr. Shipp, IP's Director of Gas Supply, explained that IP plans for capital improvements for its storage fields on a rolling five year basis and that "I do not believe that any capital projects that were viewed as necessary or desirable within a five year plan have been omitted due to lack of adequate capital budget." (Rev. IP Ex. 13.1, p. 23) He stated that "I have been in my present position through four budgeting cycles and in my tenure the storage fields have never had a requested project rejected by management due to capital budget limitations." (*Id.*) Mr. Shipp presented a detailed list of the projects and enhancements that Illinois Power has implemented at all of its storage fields over the period 1995-2003, and a detailed list of all the studies that IP performed on its storage fields during the period 1998-2003 (IP Ex. 13.6-13.7). He pointed out that Mr. Lounsberry failed to identify any storage field projects that IP should have implemented but has not implemented. (Rev. IP Ex. 13.1, pp. 23-24) Finally, concerning Mr. Lounsberry's assertions relating to capital projects and the PGA, Mr. Shipp explained that in determining whether to undertake discretionary capital projects (i.e., projects that are not necessary due to regulatory or safety requirements, to support new customer business (demand) or to replace failed or obsolete equipment), IP evaluates whether the project will result in a *lower*

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[54]Note however that IP's actual storage field capital expenditures in 2001 were higher, by a considerable margin, than the storage field capital expenditures in any of the preceding four years. (See Order in Docket 01-0701 (Feb. 19, 2004), p. 20)

overall cost of service, not just on whether or not the costs of the project will impact the PGA. (Rev. IP Ex. 13.9, p. 17)

As with his concern about the number of supervisors at the storage fields, Mr. Lounsberry failed to show any connection between IP's level of capital spending for its storage fields and the specific Hillsboro deliverability decline or IP's ability to resolve that problem. To the contrary, Mr. Hood and Mr. Kemppainen testified:

> The turbine metering injection error and the failure to discover the error sooner did not result from the failure to undertake any particular capital projects or from the level of capital expenditures generally. As we and Mr. Hower have described in our rebuttal testimonies, Illinois Power devoted considerable internal and external resources to determining the source of the Hillsboro performance decline that is the basis for Mr. Lounsberry's proposed used and useful adjustment. (IP Ex. 14.3, p. 14)

e. December 2000 Hillsboro Incident

Another of Mr. Lounsberry's concerns was that IP failed to conduct an adequate root cause analysis in connection with a December 2000 incident at the Hillsboro Field in which a produced water tank became overpressurized and was launched from its foundation, resulting in damage to other structures and equipment, an outage at the Field for five days and reduced operations for approximately the following month. (Staff Ex. 7.0, pp. 39-46; Staff Ex. 17.0R, pp. 42-44) As the Commission knows, this incident has been a topic in several previous dockets including Docket 00-0714 and Docket 01-0701. Without belaboring or repeating this debate again, Illinois Power notes the following points:

- Promptly following the December 2000 incident, IP hired a qualified outside engineering firm, Packer Engineering, to conduct an investigation of the incident and submit a report, which Packer did. Mr. Lounsberry did not question Packer's qualifications to carry out this assignment. (Rev. IP Ex. 14.1, p. 28; Staff Ex. 7.0, pp. 40-41; Staff Ex. 17.0R, p. 44; IP Ex. 14.3, p. 15))

- The Commission's Office of Pipeline Safety ("OPS") conducted a thorough, independent investigation of the December 2000 Hillsboro incident and issued a report on it, but did not make any findings of violations or non-compliances by IP. (Rev. IP Ex. 13.1, p. 18; Rev. IP Ex. 14.1, p. 33; see IP Ex. 14.4)

- The OPS Report itself reached no conclusion as to what was the root cause of the December 2000 incident. (Rev. IP Ex. 14.1, p. 31)

- The OPS report (which was completed almost ten months after the December 2000 incident) did not question the quality of IP's investigation of the incident, and OPS has never expressed any concerns to IP on this topic through other means. (IP Ex. 14.3, p. 16)

Most importantly, IP implemented a number of corrective actions pertaining to the equipment involved in the incident and its operation, some of which were based on Packer Engineering's recommendations, to attempt to prevent a repeat of the incident. These corrective actions were detailed at pages 31-32 of Revised IP Exhibit 14.1. Mr. Lounsberry did not criticize as insufficient, incomplete or inappropriate any of the corrective actions that IP implemented in response to the December 2000 incident.[55] Conducting a root cause analysis is not an end in itself but rather is a means to determine what to do to prevent the problem or incident from occurring again. In light of the fact that Mr. Lounsberry has not suggested any deficiencies in the corrective actions that Illinois Power implemented, there is no point to his continuing assertions that IP failed, in his view, to conduct an adequate root cause analysis. (IP Ex. 14.3, p. 15)

In any event, there is no connection between the December 2000 incident or its causes and the turbine injection metering measurement error that was the cause of the decline in the performance of the Hillsboro Field, and Mr. Lounsberry has not shown any connection. Further, even if the Commission were to conclude that IP's investigation of the root cause of the December 2000 incident was insufficient or not aggressive enough, this would provide no basis

[55]The Commission's OPS also has not questioned the quality of IP's corrective actions for the December 2000 incident. (IP Ex. 14.3, pp. 15-16)

to cast doubt on the sufficiency and diligence of Illinois Power's investigation into the causes of the Hillsboro Field deliverability decline (which was described in Section II.B above), or to question the sufficiency of the resources and attention that Illinois Power devoted to that problem. (IP Ex. 14.3, p. 16)

f. <u>Hillsboro Storage Field Metering</u>

Mr. Lounsberry's next "overall storage concern" was that IP did not pull the orifice plates on the Hillsboro well withdrawal meters from their installation in 1993 to the time of the Peterson metering review in 1999. He noted that (according to the Peterson report), when the orifice plates were pulled in 1999, they were dirty, and that dirty orifice plates can introduce metering errors, which can be in either direction. He asserted that IP should have inspected the orifice plates annually as specified in 83 Illinois Administrative Code Part 500, even though he acknowledged that Code Part 500 applies only to utility meters used to measure customer loads and therefore is inapplicable to the metering at the Hillsboro Field. (Staff Ex. 7.0, pp. 46-50)

Although Mr. Lounsberry was correct that the orifice plates were not pulled for inspection from 1993 to 1999, when they were pulled they were found not to have degraded after six years of service and to still be service worthy. (Rev. IP Ex. 14.1, p. 35) IP did have an inspection procedure for these meters, consisting of calibrating the differential transmitters of each orifice meter fitting, calibrating the pressure transmitters for each pipeline, and checking the calibration of the resistant temperature detectors for proper temperature input, as well as checking the signal tubing between the orifice fitting and the differential transmitter on each meter for fluids. (*Id.*) As to Mr. Lounsberry's citation of Code Part 500 as a basis for this concern, he admitted himself that Part 500 is not applicable to the Hillsboro orifice meters.

Therefore there is no point to his effort to evaluate IP's metering practices at Hillsboro against a standard that does not apply to those meters. (*Id.*, p. 33)

Mr. Lounsberry also cited the "AGA Gas Measurement Manual, Orifice Meters, Part No. 3" and asserted that IP failed to follow minimum requirements from the AGA guidelines with respect to the Hillsboro metering. (Staff Ex. 17.0R, pp. 45-47) However, this document, like Part 500, is applicable to custody transfer meters, and thus is not applicable to the Hillsboro orifice withdrawal meters. Thus, the fact that IP does not inspect the orifice plates in the Hillsboro withdrawal meters at the frequencies specified in Code Part 500 and the referenced AGA Guide does not support Mr. Lounsberry's assertions that IP did not place a high priority on accurate measurements at the Field. (IP Ex. 14.3, p. 17) Mr. Lounsberry apparently believed that IP should have used more stringent inspection and testing guidelines for these meters (Staff Ex. 17.0R, p. 47), but he provided no reason why IP should have applied regulations, standards and guidelines that are not applicable to the metering at the Field. (IP Ex. 14.3, p. 18) Moreover, the Peterson Engineering report on the Hillsboro metering in fact found with respect to the withdrawal metering installations that "In general, the metering layout is well designed and is in general conformance with AGA Report #3, Part 2". (Rev. IP Ex. 14.1, p. 36)

In any event, the problem with the orifice withdrawal meter at the Hillsboro Field was not caused by deterioration due to a lack of maintenance but rather was due to the fact that the label placed on the orifice plate by its manufacturer stated that the orifice opening was the size that Illinois Power had ordered, when in fact the orifice opening was somewhat smaller than the labeled (and ordered) size. (IP Ex. 14.3, p. 17) Further, neither the incorrect size of the orifice meter plate opening nor the level of maintenance on the orifice metering was the cause of the deliverability decline experienced at the Hillsboro Field. (*Id.*, p. 18)

g. Gas Dispatch Tracking

Mr. Lounsberry's final "overall storage concern" was that Illinois Power's gas load forecasting and dispatch group failed to notice an extra bcf of gas entering its system each year (i.e., purchased gas that IP believed, due to the inaccurate turbine metering, was being injected into the Hillsboro Field when it in fact was not but rather was entering IP's transmission and distribution system). He asserted that this was an example of IP failing to adequately oversee its operations. (Staff Ex. 7.0, p. 52)

However, the 1 bcf of gas each year that Mr. Lounsberry referred to equates to about 4,000 mcf per day on average during the injection season. Particularly during the months of April, May, October and November, when the purchased volume on any day is approximately 300,000-400,000 mcf, with approximately 120,000 mcf being injected into storage, 4,000 mcf would not stand out as a significant error. Volumes of customer-owned gas also enter the system; on a real-time basis, the dispatchers cannot distinguish between deliveries for transport customers and other deliveries into the system.[56] Further, IP's retail transportation tariff, Service Classification 76, allows transportation customers a daily variance of 50% between nominations and deliveries, which equates to a potential difference between the aggregate nominations and aggregate deliveries of transportation customers in the IP system of 30,000 to 35,000 mcf in a day – far in excess of the 4,000 mcf average daily measurement error that occurred. (Rev. IP Ex. 13.1, pp. 24-25; Rev. IP Ex. 13.9, pp. 18-19)

Moreover, on any given day the line pack in IP's system could range from zero to 10,000 mcf. The additional amounts of gas that were entering the distribution system on a daily basis

[56]On a July day the amount of gas entering IP's distribution system, including both IP purchases and the gas of transportation customers, could be 220,000 to 280,000 mcf. Again, 4,000 mcf in a day would not be noticeable in the context of these daily incoming volumes. (Rev. IP Ex. 13.9, pp. 18-19)

due to the Hillsboro injection metering error were less than the amount of gas IP typically has in its system as line pack (Rev. IP Ex. 13.1, pp. 24-25) Finally, although IP's gas dispatchers know what actual pipeline deliveries are on any day, the dispatchers do not know the actual customer consumption on any given day to enable them to compare the two values to determine if the load is equal to deliveries. The vast majority of IP's end use customers are not metered on a daily basis, but on a non-calendar monthly billing cycle basis. (Rev. IP Ex. 13.9, pp. 19) Thus, Mr. Lounsberry's assertion that IP's gas dispatchers should have noticed 1 bcf of additional gas each year entering IP's system is unsupportable when analyzed in the light of operational realities and the daily volumes on the gas system.

5. Overall Conclusion on Used and Useful Adjustment

The foregoing discussion in this Section II.D demonstrates that Mr. Lounsberry's proposed used and useful disallowance for the Hillsboro Storage Field must be rejected, and that Hillsboro is fully used and useful. Hillsboro meets the statutory tests of "necessary to meet customer demand" and "economically beneficial". Mr. Lounsberry's flawed, inappropriate and unreasonably stringent used and useful methodology does not demonstrate otherwise. Finally, Mr. Lounsberry's "overall storage concerns" lend no support to his proposed used and useful disallowance for the Hillsboro Storage Field. The Commission should include the Hillsboro Storage Field in rate base as fully used and useful.

III. COST OF SERVICE, REVENUE ALLOCATION AND RATE DESIGN

A. Cost of Service Study

1. Average and Excess versus Average and Peak Allocation Method

In its direct case, Illinois Power used the Average & Excess ("A & E") demand cost allocation method in its gas embedded cost of service study. (See IP Ex. 5.1, pp. 3-9) Staff, in its direct case, advocated the use of the Average & Peak ("A & P") method. Staff witness Lazare testified at length to the reasons why Staff was supporting the A & P method. (Staff Ex. 6.0, pp. 5-10) Both AmerenIP witness Althoff and Staff witness Lazare explained the differences and/or similarities between the A & E and A & P methods. (IP Ex. 5.6, pp. 3-5; Staff Ex. 6.0, pp. 7-10) In general, the "average" component of both methods is effectively determined in the same manner. However, with the A & E method, customer class non-coincident peak demand is utilized in the "excess" calculation, recognizing that not all customers peak at the time of the annual total delivery system peak, whereas in the A & P method, the class peak coincident with system peak is used in the "peak" portion of the allocation. (IP Ex. 5.6, p. 3)

After due consideration, AmerenIP agreed for purposes of this case to employ the A & P method, with one modification in regard to the allocation of transmission and distribution plant ("T&D"), namely, to exclude the peak demands of grain drying and asphalt customers from the calculation. (IP Ex. 5.6, pp. 5-6) Because the Commission has in recent gas rate cases supported the A & P method as opposed to the A & E method, as was explained in greater detail by Staff witness Lazare, and because the net results in employing the two different cost of service methods are reasonably close, AmerenIP agreed to the A & P method. (*Id.*; IP Ex. 5.10, pp. 2-3) A comparison of the results in terms of the allocation of T&D costs to the customer classes is as follows (IP Ex. 5.10, p. 3):

	Transmission		Distribution	
Service Classification	**A&P**	**A&E**	**A&P**	**A&E**
51	52.19%	54.04%	66.15%	67.32%
63	15.38	15.90	18.49	18.78
64	4.72	4.99	5.32	5.55
65	4.31	3.69	3.02	2.51
66	1.53	1.41	0.53	0.49
76	16.12	13.55	6.40	5.23
90	5.75	6.42	0.09	0.12
Total	100.00%	100.00%	100.00%	100/00%

As can be plainly seen from the table above, there is but a few percentage points difference between the two methods in terms of the percent of the T&D allocators by class. For example, customers in the SC 76 class see a 2.57 percentage point difference in the allocation of transmission costs and a 1.17 percentage point difference in the allocation of distribution costs between the two methods. The SC 90 customer (also an IIEC member (Tr. 179)) actually sees a decrease in the allocation of T&D costs through the use of the A&P rather than the A&E method.

Although AmerenIP believes that on a theoretical basis the A&E allocation method is superior, AmerenIP has agreed to use a modified A&P approach in this case due to the recent trend in Commission decisions on this point in gas rate cases and, more significantly, the minimal difference in results produced in the context of this case.

2. <u>Allocation of Cost of Mains</u>

As stated in the immediately preceding subsection, AmerenIP agreed with Staff to employ the A & P cost of service method for this particular case to allocate T&D plant (including mains), but with the peak demands of grain drying and asphalt customers excluded from the calculation. (IP Ex. 5.6, pp. 5-6) Staff witness Lazare agreed with AmerenIP's modified A&P approach for the allocation of mains, noting that "Any customer classes that fail to use gas during the peak day should not be factored into the peak demand component of the A&P allocator." He incorporated IP's revisions into his cost of service study. (Staff Ex. 16.0, p. 2)

Both IIEC and BEAR disagreed with the Company's allocation of mains, but for differing reasons. IIEC witness Rosenberg looked at the 10 largest customers on the system and derived from his analysis a claim that they were being over-allocated costs associated with mains. Dr. Rosenberg's analysis was based on a calculation that relied on IP's response to IIEC data request 1.34. Relying on information contained in the data request, he derived a cost of $9.45 for 12-inch steel pipe. However, as the data request response plainly states, the information therein is not complete. That is, the Company was careful to point out that while the information provided in the response was responsive to the data request, the mains costs associated with yet to be categorized plant from completed projects, main-related costs not directly categorized by main material and size, and pro forma adjustments, were not included. (IP Cross Ex. 2; IP Ex. 8.6, p. 10) So, from the outset, Dr. Rosenberg used an incomplete data set in his analysis.

In addition, Dr. Rosenberg failed to account for the fact that mains are installed to serve all customers. It is inappropriate to select some portion of the mains and assume it is only serving these 10 large customers. There is no question that mains are common to all customers and are used to bring gas from the interstate pipeline into localized systems. IIEC's analysis excluded completely the cost of these common mains and more importantly, did not allocate any of those costs to Dr. Rosenberg's select group of customers. (IP Ex. 5.6, p. 11) So, once more, he relied upon incomplete data in formulating his conclusion.[57]

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[57]Moreover, Dr. Rosenberg did not actually identify the costs that have been invested to serve these ten large customers. He applied system average gross plant costs for the various types and sizes of high pressure pipes to the length of the type of pipe installed to each of these customers.

BEAR argued, in essence, that the “average” component for the cost of service method should be based on 365 days for all classes, meaning that in determining the proper allocation factor there should be recognition that grain drying and asphalt customers are consuming gas each day of the year, as is the case for the Company’s other customers. (BEAR Ex. 1, p. 4) IP witness Jones testified that the Company allocated the average cost to SC 66 customers by taking their annual use divided by 61 days for grain dryers and 184 days for asphalt customers. These specific numbers of days were used for these customers because 90% of their usage for the year occurs during these time frames. Indeed, there are many days throughout the year when these customers consume no gas. Therefore, in was appropriate for IP to recognize this cost causation factor in determining the correct allocator. To do otherwise would only serve to inappropriately place more costs on other customers. (IP Ex. 7.30, pp. 7-8)

BEAR witness Smith also complained that IP allocated a portion of peak costs to SC 66. (BEAR Ex. 1, pp. 5, 6; BEAR Ex. 2, p. 8) However, IP witness Althoff testified in her rebuttal testimony that no excess or peak costs were allocated to SC 66. (IP Ex. 5.6, p. 5; IP Ex. 7.30, p. 10) Further, BEAR witness Smith stated that distribution plant should reflect a measure of average and peak use, and that IP has built its system to serve its winter peak load. (BEAR Ex. 1, p. 5) Her premise was incorrect. IP plans and builds its T&D plant to meet customers’ loads regardless of when or where they occur on the system. For grain drying customers, groupings of pipes (or localized systems) are built to handle their loads during their peak drying season, which does not occur in the winter season. (IP Ex. 5.6, pp. 6-7) In fact, the data show that grain drying

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He did not calculate the actual cost that IP has incurred to install the specific facilities that serve each of these customers. (Tr. 182-84) This is one more example of Dr. Rosenberg relying on flawed or incomplete data in support of his proposals.

customers' demands spike in the Fall. (IP Ex. 7.19, p. 20; IP Ex. 7.26) In any event, the Company allocated no "peak" costs to SC 66.[58] (IP Ex. 7.30, p. 10)

As is more than obvious, the Company applied an empirical, objective analysis in its approach, in contrast to BEAR's approach, which is driven by end results objectives only, and is without any basis in fact. In addition, as noted above, Staff witness Mr. Lazare accepted IP's rationale when developing his T&D allocators. (Staff Ex. 16.0, p. 2; see IP Ex. 5.6, pp. 7-8)

In summary, the allocation of mains used by Illinois Power in this case, and endorsed by Staff, is a broad based allocator that also distributes common mains to all customer groups. Further, IP's allocator takes into account the usage periods of the customer classes. IIEC's and BEAR's concerns are unpersuasive and do not provide a basis for not using IP's allocations.

3. Allocation of Cost of Services

Another cost of service issue raised in this proceeding relates to the allocation to the customer classes of the costs of services connecting customer premises to the gas system. Services are included in the category of customer-related costs. Customer-related costs typically include capital investment associated with metering equipment and service connections as well as expenses for meter reading, billing, collecting and accounting. (See IP Ex. 5.1, pp. 4-6) Both Staff and BEAR raised objections to AmerenIP's proposed cost of service allocator for services.

Staff witness Lazare disagreed with IP's allocator because IP's allocation method, in his view, relied on questionable data concerning (i) the breakdown between steel service pipes and plastic pipes on the system and (ii) the relative costs of steel and plastic pipe. In support of his

[58] As the table in the previous subsection shows, both the A&P and the A&E methods allocate only about 1.5% of the total transmission plant and only about 0.5% of the total distribution plant to SC 66. "Capacity" related costs are a relatively minor part of the cost of service for this class. Further, even if SC 66 were allocated *no* T&D plant, a rate increase would still be necessary to these customers just to recover customer-related costs. (IP Ex. 7.30, pp. 12-13)

observation, he relied upon information provided by IP to the United States Department of Transportation ("USDOT"), which seemed to be inconsistent with data IP had used in performing its allocation. (Staff Ex. 6.0R, pp. 13-15)

Bear witness Smith also questioned the data set on which IP relied in developing the services allocator. Further, Ms. Smith offered the view that cost differences between plastic and steel services varied with load, and that this factor should be taken into account in determining the allocation. (BEAR Ex. 1, pp. 8-9)

Based on the concerns expressed by Staff witness Lazare and BEAR witness Smith, AmerenIP witness Althoff performed an additional review of the services allocator. Ms. Althoff observed that older services data tracked in the Company's system did not record a diameter size when the corresponding services were installed; as a result, because the size of the services were not tracked, these services were placed in the "zero" size category. However, more recently-installed services are now categorized by size. Accordingly, Ms. Althoff relied upon the more recently-installed services, which were categorized by size, to reallocate the older "zero" size services. The reallocation of the "zero" size services takes into consideration all services installed, both steel and plastic, which should resolve certain of the Staff and BEAR concerns. (See IP Ex. 5.6, p. 14 and IP Ex. 5.10, p. 7)

The results based on AmerenIP's revised services allocator are fairly consistent with the information that IP provided to USDOT. Staff witness Lazare had testified that the USDOT report showed steel services at less than 40% of the total and plastic services at 60%. (Staff Ex. 6.0R, pp. 13-14) AmerenIP's revised services allocator indicates that 35% of the services are steel and 65% are plastic, which is consistent with not only the information in the USDOT report, but also with AmerenIP's records. With this refinement, the Staff allocations and the revised Company allocations of total services costs to the customer classes now track fairly closely, as summarized in Ms. Althoff's rebuttal testimony (IP Ex. 5.6, pp. 16-17):

Service Classification	**Staff Direct**	**Revised Company**
SC 51	84.25%	80.23%
SC 63	14.59%	17.01%
SC 64	00.72%	01.70%
SC 65	00.11%	00.30%
SC 67	00.11%	00.28%
SC 68	0.01%	00.03%
SC 76	00.20%	00.46%
SC 90	00.00%	00.80%

Even though AmerenIP revised and justified the services database on which it based its revised services allocation, and which is now consistent with information AmerenIP has provided to the USDOT, so that the results of IP's revised allocator are now fairly consistent with Staff's proposal, Mr. Lazare continued to defend his proposal even with its stated flaws. AmerenIP has provided a revised services allocator that is cost-justified; Mr. Lazare, in contrast, utilized a simple averaging based on an incomplete data set. In Staff Schedule 6.04, page 3, Mr. Lazare relied on a unit cost for steel and plastic, added them together and divided by two. He then used the resulting average cost for service pipe sizes of 1-inch or less as the basis for developing size-cost weighting factors which are reflected in the fifth column of his Schedule 6.04. Mr. Lazare used the size cost weighting factors in the eventual development of the services allocation as reflected on Staff Schedule 6.04, page 4. The only rationale given for averaging the unit cost of steel and the unit cost of plastic is that Staff found the original data set relied upon by

AmerenIP to be unreliable. This concern should no longer be a consideration since, as described above, IP's data set was improved and shown to be reliable in the Company's rebuttal case.

In developing his services allocator, Mr. Lazare relied in part on information provided by the Company in response to IIEC data request 1.33. In particular (as reflected on Staff Schedule 6.03, which is the schedule that develops the unit cost), Mr. Lazare relied on the linear feet and gross plant balance information from the data request response. However, the data request response, which was introduced as IP Cross Exhibit 1, plainly stated that the information provided in the data request response did not include all relevant costs. Specifically, the cost data provided in the response to IIEC data request 1.33 "do not reflect amounts associated with yet to be categorized main from completed projects, main related costs not directly categorized by main material and size (e.g. valves, fittings, filters, etc.) and proforma adjustments (e.g. CWIP to In-Service, etc.)" Therefore, the data request information could not provide the basis for depicting all the costs associated with service allocators.

Staff witness Lazare's averaging method for developing the services allocator is further debunked by a comparison of the relative cost differences between plastic and steel pipe. As shown in Ms. Althoff's rebuttal testimony, depending on the size of the pipe, the variance in cost between plastic and steel can vary. For example, steel is 14 times more costly than plastic with regard to pipe that is 1 inch in diameter; however, steel is only 3 times more costly than plastic when considering 4 inch diameter pipe, and only 1.5 times greater for 6 inch diameter pipe. As a result, the simple averaging approach supported by Mr. Lazare merely increased the cost assigned to the residential customer class. (IP Ex. 5.6, p. 16)

Another notable flaw in Mr. Lazare's approach is the fact that it allocates no services cost to the SC 90 customer class. Mr. Lazare provided no evidence to suggest or even imply that there are no capital costs or expenses for services attributable to this customer. Similarly, under Mr. Lazare's services allocator, the SC 76 class, which has 191 customers, would only be allocated 0.2% of the total service costs whereas under IP's allocator 0.46% of the services cost would be allocated to this class. (IP Ex. 5.6, pp. 16-17)

Turning to BEAR's criticisms of IP's services allocator, BEAR witness Smith was critical of the original database employed by the Company in determining the services allocator. As explained above, this problem was remedied in the Company's rebuttal testimony. Ms. Smith also expressed concerns about the relative costs of plastic and steel pipe and the sizes of the pipes in relationship to load. However, Ms. Smith ignored the fact that pipe selection is based on the amount of gas delivered to the customer and the pressure at which customers are served, and that higher pressure customers require steel services, which are more costly that plastic pipe with respect to both material and labor (installation) costs. (IP Ex. 5.6, p. 18)

In her rebuttal testimony, BEAR witness Smith asserted at one point, "it is usually assumed that current costs can serve as a reasonable proxy for historic costs" but, in contrast, she also stated that "using current costs as a basis for allocation would not be correct". (BEAR Ex. 2, p. 7) This contradiction cannot be explained away. Nonetheless, AmerenIP witness Althoff testified that the use of current costs provides a better basis for allocating costs to customer classes as it eliminates the varying impacts of inflation on different plant items that is present when historic costs are used. In addition, IP's books and records are maintained in accordance with the Federal Energy Regulatory Commission's Uniform System of Accounts, which only requires the recording of plant and expenses by account without a customer class designation. Ms. Althoff also noted that the current cost approach is consistent with the Commission decisions in IP's delivery service tariff cases (Dockets 99-0134 and 01-0432) where the

Commission approved the use of current costs for electric service drops (as well as meters) to allocate the embedded costs of those plant items. (IP Ex. 5.10, p. 11; see *Illinois Power Company*, Docket 01-0432, Order (Mar. 28, 2002), pp. 59-61)

In summary, IP's allocation of the costs of services to the customer classes, as revised in IP witness Althoff's rebuttal testimony, should be accepted for purposes of this case. IP's revised services allocator addresses the concerns originally expressed by Staff witness Lazare, and produces results quite similar to Staff's proposal. The unfocused criticisms of BEAR should be rejected.

4. Use of AmerenIP Cost of Service Study versus Staff Cost of Service Study

Staff witness Lazare testified that Staff's cost of service model and study, rather than IP's cost of service study, should be used for purposes of this proceeding.[59] AmerenIP expresses strong disagreement that Staff's cost of service model should be used to set rates in this proceeding. Ms. Althoff pointed to a number of flaws in the Staff model and study. Aside from concerns regarding terminology, the use of pasted values, and the lack of clarity with regard to certain of the formulas and other input data, Staff is using data from the Company's model to develop Staff's cost of service results. As she described it, Staff's model relied on a "hodge-podge of data." (IP Ex. 5.6, pp. 21-22) This is extremely problematic and is sure to lead to incomplete and confusing results.

Additionally, AmerenIP witness Jones testified that whereas AmerenIP's cost of service model is able to calculate the revenue requirement by function, the Staff model is deficient in

[59]Mr. Lazare's position was based at least in part on his concerns relating to having to enter into a confidentiality agreement with the vendor that provides IP's cost of service model, in order to be able to obtain a complete copy of the cost of service study. These concerns are discussed in Section IV.A.6, below.

this respect. (IP Ex. 7.19, p. 29) Mr. Jones' conclusions were not disputed by Staff. In the end, use of Staff's cost of service model cannot be the basis on which rates are set in this proceeding, as to do so would lead to unintended results.

5. Allocation of Overall Revenue Requirement to the Customer Classes

As discussed in Sections III.A.1 through 4 above, there are issues among the parties concerning the methodologies for allocating various costs in the embedded cost of service study, and indeed as to which cost of service study should be used for purposes of this case. However, the approved overall revenue requirement should be allocated among the customer classes using the approved cost of service study so as to achieve equalized class rates of return. (IP Ex. 7.10, p. 6) In other words, the approved cost of service study will provide the basis for allocating the final revenue requirement (and thus the base rate increase) among the customer classes. There is only one exception to this equalized rate of return approach: IP presently serves one customer on a contract under SC 90, Contract Service. Under the terms of that contract, the pricing under the contract is exempt from being changed due to a general rate increase proceeding. Therefore, to the extent that the equalized rate of return approach would have resulted in a rate increase for the SC 90 customer, the incremental revenue that would have resulted from increasing rates to the SC 90 customer must be allocated among the other classes. (*Id.*, pp. 6-7)

For purposes of allocating the overall revenue requirement to the customer classes, Illinois Power utilized the following classes: (i) SC 51, Residential Gas Service; (ii) SC 63, (non-residential) Small Volume Firm Gas Service; (iii) SC 64, (non-residential) Intermediate Volume Firm Gas Service; (iv) SC 66, Seasonal Gas Service (this class is comprised former SC 67 and SC 68, which SC 66 is replacing); (iv) SC 65 and SC 76, Industrial Gas Service; and (v) SC 90, Contract Service. IP grouped SC 65, Large Volume Firm Gas Service, and SC 76, Transportation of Customer-Supplied Gas with Best Efforts Backup, together for revenue allocation purposes because SC 65 and SC 76 generally constitute the IP's industrial class, and customers can periodically switch between these two service classifications. (IP Ex. 7.10, p. 6)

The ALJ requested that the parties submit an attachment or attachments with their initial briefs showing their proposed allocations of the revenue requirement among the customer classes and their proposed rates and charges, along with a comparison to current rates and charges.[60] IP Appendix A and IP Appendix B to this Brief, each consisting of four schedules, is Illinois Power's response to this request.[61] Using IP Appendix B, Schedule 2, page 1 for illustration, the overall approved base rate revenue requirement is $141,456,604, of which $4,067,000 would be recovered as miscellaneous revenues.[62] This leaves a net amount of $137,389,604 to be recovered through rates charged under the various service classifications. (See Schedule 2, p. 2, col. (2).) Schedule 1 in IP Appendix B shows the allocation of this net revenue requirement to

[60]This case is somewhat unusual as compared to most rate cases in that because there are only two remaining revenue requirements issues and all other issues have been stipulated or otherwise revised, the minimum and maximum base rate revenue requirements and rate increases that will result from this case are known. As shown on Appendices A and B to the Stipulation between IP and Staff filed January 21, 2005 in this case, the minimum base rate revenue requirement and rate increase are $138,566,000 and $11,336,000, while the maximum base rate revenue requirement and rate increase are $141,457,000 and $14,227,000. Because of the high degree of certainty as to the range of possible outcomes in this case, it is possible for the parties to calculate and present specific proposed interclass allocations of the minimum and maximum revenue requirement amounts.

[61]Schedule 1 to each Appendix is similar in format to IP Exhibits 5.5 and 5.8, which were sponsored by IP witness Karen Althoff in her supplemental direct and rebuttal testimonies, respectively. Schedule 2 to each Appendix is in similar format to IP Exhibits 7.11 and 7.20; Schedule 3 is in similar format to IP Exhibits 7.17 and 7.23, and Schedule 4 is in similar format to IP Exhibits 7.18 and 7.24, all of which were sponsored in this case by IP witness Leonard Jones in his supplemental direct and rebuttal testimonies, respectively.

[62]Miscellaneous revenues include forfeited discounts (late payment charges), reconnect charges, gas service activation fees, equipment rentals, farm and lease income, non-sufficient check charges and certain charges for emergency service calls (IP Ex. 5.1, p. 9), and the accounting fee IP retains for billing, collecting and remitting municipal utility taxes. (IP Ex. 2.35, p. 26)

the customer classes based on the embedded cost of service study. Schedule 2, page 1, column (6) shows that (taking into account that no revenue increase can be allocated to the SC 90 class), the $137,389,604 to be recovered through rates charged under the service classifications is allocated among the customer classes as shown in the table below. Similarly, Schedule 2, page 2, columns (2) and (7) show that the $14,227,000 base rate increase is allocated among the classes as follows:

Class	Constrained Revenue Requirement Allocation	Revenue Increase Allocation
SC 51 (Residential	$ 94,367,237	$ 5,272,995
SC 63 (Small Volume Firm)	$ 24,961,155	$ 4,951,857
SC 64 (Intermediate Volume Firm)	$ 5,792,893	$ 1,590,135
SC 66 (Seasonal)	$ 1,140,930	$ 536,190[63]
SC 65/76 (Industrial)	$ 9,886,510	$ 1,875,747
SC 90 (Contract)	$ 1,240,878	--
Totals	$137,389,604	$14,226,923[64]

Staff witness Peter Lazare, in his rebuttal testimony, presented a proposed interclass revenue allocation based on a revenue requirement and rate increase for IP of $144,969,000 and $21,806,000, respectively. (Staff Sched. 16.02) He also presented specific proposed rates and charges for the individual service classifications to recover this revenue requirement. (Staff Sched. 16.03) He then testified that if the final revenue requirement and rate increase amounts were lower than the values he used on Schedule 16.02, the rates developed in his Schedule 16.03 should be prorated down on an equal percentage basis to conform to the final approved revenue

[63]The actual net increase to the SC 66 class is $245,490 due to a decrease in this class's PGA charges because these customers will be billed the Rider B Commodity Gas Charge rather than the Rider A Gas Charge. (See IP Appendix B, Sched. 2, p. 2, col. (7))

[64]The actual net increase in total revenues is $13,936,224 due to the decrease in the PGA charges to the SC 66 class because these customers will be billed the Rider B Commodity Gas Charge rather than the Rider A Gas Charge. (See IP Appendix B, Sched. 2, p. 2, col. (7))

requirement. He asserted that re-running the cost of service study to allocate the final approved revenue requirement to the customer classes would require time and effort and contained the potential for errors, and that the incremental accuracy that would be achieved did not justify the attendant time and energy. (Staff Ex. 16.0, pp. 12-14)

In light of the ALJ's directions to the parties to provide with their briefs a schedule showing their proposed rates and charges, and the tight range of possible overall revenue requirement outcomes in this case, Illinois Power does not know (and will not know till it receives Staff's initial brief) if Mr. Lazare will adhere to the position he articulated in his rebuttal testimony, or instead will rerun his cost of service analysis and present proposed rates and charges for the $11,336,000 and $14,227,000 revenue increase scenarios (as the Company has done). Certainly, the effort he envisioned to do this is less than might have been the case had IP and Staff not entered into the Stipulation resolving numerous then-outstanding revenue requirement issues. Further, the ALJ has provided the opportunity for the parties to prepare and submit their proposed allocations of the minimum and maximum revenue requirement amounts that will result in this case.[65] However, for the reasons stated in IP witness Mr. Jones' surrebuttal testimony (IP Ex. 7.30, pp. 13-14), the Company believes Mr. Lazare's "proration" approach is inappropriate, particularly given the significant difference between the revenue requirement for which Mr. Lazare presented a proposed allocation in his rebuttal testimony and the minimum and maximum revenue requirement amounts that will result in this case due to the Stipulation. If Staff, in its initial brief and its attachment in response to the ALJ's request, simply uses a

[65]IP assumes that Mr. Lazare's position was motivated in large part by the fact that Commission rate orders typically provide for a three to five business day period following the utility's filing of its compliance tariffs for Staff to verify that the tariffs in fact comply with the order and produce the authorized revenue requirement and rate increase. In this case, however, the ALJ (and the Stipulation) have provided an opportunity to do most or all of this work in advance of the final order being issued.

proration approach from the rebuttal revenue requirement, the Company will address the problems and deficiencies with this approach in its reply brief.

BEAR witness Smith suggested that the revenue increase allocated to the SC 66 class should be no higher than 50% more than the system average increase. (BEAR Ex. 2, p. 13) As shown on Schedule 2, page 2, columns (7) and (8) of IP Appendices A and B, IP's proposed revenue allocations to SC 66 in both the "low" and "high" revenue requirement scenarios exceed this limit, but the proposed percentage increase to the SC 66 class is modest in any event (i.e., approximately a 7% increase in total revenue (including PGA revenue) to be billed to this class). The limit proposed by BEAR witness Smith is unnecessary. Further, if the Commission were to order a limit on the revenue increase for SC 66, the limit should be based on the total class revenue (including PGA revenue), not just base rate revenue. This is especially important with respect to current SC 67 customers moving to new SC 66, since these customers will receive the benefit of lower PGA costs (i.e., they will be subject to the Rider B Commodity Gas Charge instead of the Rider A Gas Charge which incorporates demand costs). (IP Ex. 7.30, p. 11) Finally, if the Commission accepted Ms. Smith's suggestion, the SC 66 class would be charged less than its cost of service and therefore these customers would be subsidized by all other customers. There is no justification for other customers subsidizing BEAR's members and other SC 66 customers.

6. Issues Associated with Vendor-Supplied Cost of Service Model Used by AmerenIP

In his direct testimony Staff witness Lazare registered a number of complaints with regard to AmerenIP's cost study. Specifically, he complained that outside users must sign a confidentiality agreement to review a working copy of the model, and made complaints regarding access to certain formulas within the study. (Staff Ex. 6.0R, pp. 17-18) Mr. Lazare suggested, as a response to his own concerns, that the alternative Staff cost of service model should be used to develop rates, claiming in part that the Staff model is "more straight forward and transparent than the Company study". Mr. Lazare concluded the Commission should order AmerenIP to present a non-copyright-protected cost of service study in future gas rate cases. (*Id.*, pp. 18-20) Mr. Lazare's position is wrong on several counts.

Illinois Power's cost of service study was presented in this case consistent with the applicable rules. Specifically, 83 Ill. Admin. Code Section 285.5110 describes the requirements for an embedded class cost of service study to be submitted with a gas utility's rate case. Notably, Mr. Lazare never claimed that IP's cost of service study is not in accord with such rules. (Tr. 121)

As to Mr. Lazare's complaint that Staff and others are required to execute a confidentiality agreement in order to access certain formulas, Part 285 acknowledges that a utility may be prevented from providing a working model that it obtained from an outside vendor by virtue of the utility's agreement with that vendor. In that event, the utility is permitted to have its vendor enter into an agreement with case participants to provide a working copy of the model to be used for a fixed and limited time period. As Ms. Althoff explained, Mr. Lazare requested a copy of the model about six weeks after the case was filed (which was 25 days after other Staff members had sent their initial data requests), and the model was provided after Staff signed a confidentiality agreement. (IP Ex. 5.6, p. 19; IP Ex. 5.10, p. 12) The point is that Part 285 contemplates that a confidentiality agreement may need to be signed.

Moreover, cost of service models supplied by the same vendor that supplied IP's gas cost of service model have been used by AmerenIP in the past, this same vendor has required a confidentiality agreement to be signed and, in fact, Mr. Lazare was the Staff witness in Illinois

Power's 2001 delivery service tariff ("DST") case, Docket 01-0432, where a confidentiality agreement with this vendor was required to be signed.[66] (Tr.121-122) After IP's DST case in 2001, the Commission engaged in a rulemaking to consider changes to Part 285 (Docket 02-0509). Mr. Lazare participated in the rulemaking on behalf of Staff. (Tr. 123) Part 285, including Section 285.5110, was open for discussion and changes. Indeed, there were three changes made to that section and as stated in the order from the rulemaking docket, two of the three suggestions were made by IP, and each was agreed to by the Staff. In particular, IP recommended specific language clarifying what is meant by "black box" and Staff agreed with IP's suggestion to include the phrase "i.e., formulas may be hidden to prevent viewing." (Order in Docket 02-0509 (March 26, 2003), p. 26) In summary, if the Staff had any complaints with regard to matters pertaining to the use of an outside vendor, the use of a confidentiality agreement, whether a cost of service study may have hidden formulas, and so forth (and in particular, if Mr. Lazare had any concerns based on his experience in these areas with IP's vendor-supplied cost of service model in the 2001 IP DST case), the time to address these matters was in the context of that rulemaking, and not in this rate case.

Notwithstanding the above, the fact is Staff could review all the inputs of IP's model, make changes and execute alternative scenarios. (IP Ex. 5.6, p. 19) Mr. Lazare, and any other parties that executed a confidentiality agreement, were provided a fully functioning copy of the cost of service study identical to the model that AmerenIP used. (IP Ex. 5.10, p. 12)

In summary, IP's use of its vendor-supplied cost of service model and its actions with respect to that model in this case were fully compliant with the applicable (and recently-adopted)

[66]Both IP's gas cost model in this case and its electric cost model in the DST case were developed and supplied by Management Applications Consulting, Inc., whose cost of service models have been successfully employed to perform cost studies in some 19 states, including Illinois, during the past few years. (IP Ex. 5.10, pp. 13-14)

provisions of the Commission's Part 285 rule. Mr. Lazare's complaints about the Company's cost of service model should be rejected.

B. Development of Rates and Charges

IP Appendix A and IP Appendix B to this Brief, submitted in response to the ALJ's request, shows Illinois Power's proposed rates and charges in the individual service classifications for the $11,336,000 and $14,227,000 base rate revenue increase scenarios, respectively. Specifically, Schedule 3 of each Appendix shows IP's proposed prices for each scenario, along with a comparison to the current prices.

Illinois Power witness Leonard Jones described the basis on which IP designed its proposed rates and charges for the various service classifications. (IP Ex. 7.10, pp. 8-24) The starting point, as discussed in Section III.A.5 above, is the allocation of the overall revenue requirement to the customer classes on an equalized rate of return basis using the cost of service study. Within each class, customer costs (i.e., the costs associated with serving a customer regardless of whether any gas is used, including the meter, service line, regulator, recurring meter expenses and administrative costs of servicing the account), as developed in the cost of service study, were used to develop the proposed Facilities Charges for each service classification. (*Id*., p. 8) IP Exhibit 7.21 submitted with Mr. Jones' rebuttal testimony showed the development of IP's proposed Facilities Charges based on the revenue requirement IP proposed in rebuttal. Delivery Charges and, for the service classifications on which larger-use non-residential customers are served, Demand Charges, within each service classification, were used to recover the remaining fixed costs associated with the customer's use of IP's distribution system. (IP Ex. 7.10, p. 8) IP Exhibit 7.22 submitted with Mr. Jones' rebuttal testimony showed the development of IP's proposed Delivery Charges and Demand Charges based on the revenue requirement IP proposed in rebuttal.

The following paragraphs summarize highlights of the Company's proposed rate design, particularly with respect to changes from the rate design in IP's current gas rates. Other than the rate design changes described below (and in Sections IV.A and IV.B of this Brief concerning proposed SC 66 and the transportation tariffs, respectively), IP is generally proposing increases to the existing rate elements in its gas tariffs without significant rate design changes from the current tariffs.

SC 51 (Residential) and SC 63 (non-residential Small Volume Firm). The Delivery Charges in present SC 51, Residential Gas Service, and SC 63, (non-residential) Small Volume Firm Gas Service, are both declining block rates. IP proposes that the Delivery Charges in SC 51 and SC 63 become single, flat rates applicable to all therms delivered, because all customer costs are to be recovered through the Facilities Charges in these service classifications. (IP Ex. 7.10, pp. 10, 12) There was no objection to this proposal.

SC 65 (non-residential Large Volume Firm) and SC 76 (Transportation of Customer-Supplied Gas). For SC 65, Large Volume Firm Gas Service, and SC 76, Transportation of Customer-Supplied Gas with Best Efforts Backup, separate Facilities Charges were developed for each service classification, but the transmission and distribution costs for SC 65 and SC 76 were combined to establish the cost bases for the high pressure and low pressure Demand Charges. The low pressure Demand Charge is based on the cost for the delivery assets (i.e., facilities operated at equal to or less than maximum allowable operating pressure ("MAOP") of 60 psig) required to get to the customer's location plus the cost for transmission delivery assets (i.e., facilities operated at a MAOP greater than 60 psig). The cost basis for the high pressure Demand Charge excludes the cost for the low pressure assets since customers served at high pressure do not utilize IP's low pressure system. Additionally, the SC 65 Delivery Charge recovers a portion of demand costs. (IP Ex. 7.10, pp. 13-14)

The SC 76 Facilities Charges for customers that would otherwise be served on SC 63 or SC 64 if they took firm supply gas service from IP are equal to the applicable Facilities Charges under those service classifications. (IP Ex. 7.10, pp. 19-20; see also IP Ex. 7.19, pp. 4-5) However, for customers with an average daily usage of 1,000 therms or more, separate Facilities Charges are provided in SC 76 for customers with an average daily usage of up to 10,000 therms and customers with an average daily usage of 10,000 therms or more. (IP Ex. 7.10, p. 20; see also IP Ex. 7.19, pp. 5-6) Staff witness Mr. Lazare reviewed the bases for IP's proposed SC 76 Facilities Charges and found them to be reasonable. (Staff Ex. 16.0, pp. 9-10)

Finally, IP is eliminating the Delivery Charge in SC 76 because delivering gas to SC 76 customers does not cause the Company to incur a volumetric delivery cost. (*Id.*, p. 21)

SC 66 (Seasonal Gas Service). SC 66, Seasonal Gas Service, is a new, optional tariff intended to replace existing SC 67, Firm Gas Grain Drying Service, and existing SC 68, Seasonal Gas Asphalt Service.[67] Illinois Power initially proposed that SC 66 would include separate Facilities Charges for customers with a Maximum Daily Quantity ("MDQ") or actual use less than a maximum of 1,000 therms per day and for customers with a MDQ or actual use equal to or greater than 1,000 therms per day. (IP Ex. 7.10, pp. 17-18) However, in response to customer impact concerns expressed by BEAR witness Smith, IP developed Facilities Charges for SC 66 customers delineated between customers served from facilities with MAOP equal to or less than

[67]SC 66 will be an optional tariff offering. Customers that might find SC 66 attractive will also have the option to take service on any other service classification for which the customer qualifies (i.e., firm supply service on SC 63, SC 64 or SC 65, or transportation service on SC 76). (See IP Ex. 7.19, p. 19)

60 psig and customers served from facilities with a MAOP greater than 60 psig, and with separate Facilities Charges within each of these categories for small, medium and large customers. (IP Ex. 7.19, pp. 8-13) In other words, IP is proposing that SC 66 include a menu of six Facilities Charges to better match cost recovery and pricing to the specific characteristics of the individual customers served on this tariff and the facilities that serve them. The issues relating the SC 66 Facilities Charges, as well as the overall price level and competitiveness of this rate, are discussed in greater detail in Section IV.A below.

SC 66 customers that purchase system supply gas from IP will be billed the Rider B Gas Commodity Charge under IP's PGA. (IP Ex. 7.10, p. 16) This feature of SC 66 provides a benefit particularly to grain dryers currently served on SC 67, since SC 67 customers are billed the Rider A Gas Charge. The Rider A Gas Charge recovers pipeline demand-related gas supply costs as well as commodity costs and therefore typically is higher than the Rider B Gas Commodity Charge. (IP Ex. 7.19, p. 22)

Under SC 66, customers will be billed a Delivery Demand Charge based on usage consumed on days when average temperatures are forecasted to be at or below 25 degrees Fahrenheit. IP originally proposed that the Delivery Demand Charge be applicable for usage consumed on days when the temperature is forecast to be at or below 32 degrees F., but modified this provision to 25 degrees F. during the course of the case in response to concerns expressed by BEAR witness Smith. (IP Ex. 7.10, p. 18; IP Ex. 7.30, pp. 9-10) However, SC 66 customers that have provided a contribution to IP for a delivery system improvement to expand capacity to serve the customer's load at times of system peak will be allowed to contract with IP for a Winter Delivery Allowance, which will be an amount of gas the customer can use on days when the temperature falls below the temperature criterion, without incurring a Delivery Demand

Charge. (IP Ex. 7.10, pp. 16-18) Finally, SC 66 customers consuming gas on days when the temperature falls below the temperature criterion will also be billed the Company's Rider B Gas Demand Charge in its PGA tariff, regardless of whether the customer has a Winter Delivery Allowance.[68] (*Id.*)

Development of final proposed rates and charges. As noted above, Schedule 3 in each of IP Appendix A and IP Appendix B to this Brief shows Illinois Power's proposed rates and charges for each service classification under the $11,336,000 and $14,227,000 base rate increase scenarios, respectively, along with a comparison to the current rates and charges. In his rebuttal testimony, IP witness Leonard Jones explained how the final rates and charges should be established to produce the final revenue requirement allocated to each customer class, if the final revenue requirement is less than the revenue requirement proposed by IP in rebuttal (which both the minimum and maximum revenue increases defined by the Stipulation will be). The considerations he detailed are as follows (IP Ex. 7.19, pp. 28-29):

- Residential rates (SC 51) should be cost based, except that the Non-Standard Facilities Charge should not exceed $35 due to customer impact concerns.

- Rates for SC 63 should be cost based, except that the Non-Standard Facilities Charge should not exceed $90 due to customer impact concerns.

- Rates for SC 64 should be cost based.

- For SC 65, the Facilities Charges should be set based on the allocated cost of service. To reconcile to a reduced revenue requirement, the Delivery Charge should be reduced first, all the way to zero if necessary. The Demand Charge should be the last rate component to be adjusted to reconcile to a lower revenue requirement. Due to customer impact concerns, the low pressure Demand Charge has been limited to 60.60 cents/therm and the high pressure Demand Charge has been increased to recover a portion of the resulting cost recovery shortfall; if a

[68]This is because the Rider B Gas Demand Charge recovers gas supply costs, not delivery system costs. (IP Ex. 7.10, p. 17)

further reduction is necessary, both Demand Charges should be moved closer to cost.

- Rates for SC 66 should be cost based.
- Rates for SC 76 should be cost based, and the Demand Charges should be adjusted to reconcile to a lower revenue requirement in the same manner as described for SC 65.

Mr. Jones employed these considerations in developing the proposed rates and charges shown on Schedule 3 of IP Appendix A and IP Appendix B.

As noted in Section III.A.5 above, Staff witness Lazare, in his rebuttal testimony, testified that if the final approved revenue requirement is lower than the revenue requirement presented by IP in rebuttal, which Mr. Lazare used to design the proposed rates he presented in his rebuttal testimony (Staff Schedule 16.03), then each of his proposed rates and charges should be adjusted downward on an equal percentage basis to achieve the approved revenue requirement. (Staff Ex. 16.0, p. 12) Illinois Power believes that the approach Mr. Lazare advocated is inappropriate and would disregard the considerable effort the parties to this case have devoted to revenue allocation and rate design issues. (See IP Ex. 7.30, pp. 13-14) However, in light of the ALJ's request that the parties submit attachments to their briefs setting forth proposed rates to recover the revenue requirements produced by the Stipulation, IP does not know if Mr. Lazare will adhere to his position, or if he will instead present proposed rates and charges specifically designed to recover the revenue requirements under Appendix A and Appendix B to the IP-Staff Stipulation.[69] If Staff's proposed rates are based solely on applying equal percentage reductions to the rates Staff previously presented to recover the revenue

[69] As noted in Section III.A.5 above, Mr. Lazare appeared to have been concerned about the ability to adjust rates on a cost of service basis to match the final approved revenue requirement within the limited time typically provided in Commission rate orders for the utility to file and Staff to review compliance tariffs.

requirement proposed by IP in rebuttal, Illinois Power will respond in greater detail in its reply brief.

IV. TARIFF TERMS AND CONDITIONS

A. Service Classification 66

AmerenIP proposes to implement a new tariff, SC 66, Seasonal Gas Service, directed toward providing cost-based, competitive service to seasonal use customers such as grain dryers and asphalt plants. SC 66 is an optional service intended to be available to all present SC 67 (grain drying) and SC 68 (asphalt) customers (as well as any other customers that find this tariff beneficial based on their usage characteristics). SC 67 and SC 68 would be canceled. In his direct testimony, IP witness Jones explained the principal features of proposed SC 66. (IP Ex. 7.10, pp. 15-18) Key rate provisions of proposed SC 66 are summarized in Section III.B, above.

BEAR witness Smith testified that the Facilities Charge for all SC 66 customers should be set at no more than $400, with the remaining customer-related costs allocated to all units charged.[70] (BEAR Ex. 1, p. 10) Ms. Smith took issue with AmerenIP's threshold point for the Facilities Charges allocated to SC 66 customers based on the 1,000 MDQ threshold, as proposed in IP's direct case filing. She argued for an averaging of the Facilities Charge because "it is not clear whether this is because the identification of customers at or above 1,000 is correct, or because some customers may have a meter sized for higher use, but they do not actually use as much, or because of unique characteristics of different customers, or because some customers simply have newer more expensive meters." (*Id.*)

[70] BEAR is an entity or organization that includes or represents customers that use gas for grain drying. So far as AmerenIP is aware, BEAR does not include or represent customers that use gas in asphalt-producing operations.

AmerenIP witness Jones responded in his rebuttal testimony that Ms. Smith's simple averaging recommendation failed to take into account the differing cost characteristics of customers within this seasonal gas use class. For example, he noted that Ms. Smith's own Exhibit LS-3 showed that there are 16 different meter types serving SC 67 and 68 customers. (IP Ex. 7.19, p. 6) Different meter types mean different meter costs. These cost differences should have some bearing on the overall level of the Facilities Charges.

Mr. Jones revisited IP's proposed SC 66 Facilities Charges taking into consideration the maximum demand for the customer as well as the data shown on BEAR Exhibit LS-3. He explained that the list of meter types and costs can be organized in three general groupings. The first group is meters with an installed cost of $8,500 or less, the second group is meters that cost approximately $20,000 to install, and the third group consists of meters that cost approximately $40,000 to install. He then considered hourly and daily maximum capabilities for each grouping to be matched against the expected peak hourly demand of a customer. Taking into consideration the MAOP and capacity associated with both low pressure and high pressure mains, Mr. Jones was able to develop a set of Facilities Charges for SC 66 that would be delineated between customers served from systems with a MAOP equal to or below 60 psig and those served from systems with a MAOP above 60 psig. Mr. Jones then developed a cost basis for the proposed SC 66 Facilities Charge based on the two new usage categories he developed, each of which would have three different levels of charges for small, medium, and large SC 66 customers. (IP Ex. 7.19, pp. 8-12)

In her rebuttal testimony, rather than refuting (or accepting) the cost-based justification and revised Facilities Charges developed by Mr. Jones in his rebuttal, Ms. Smith argued that "the proposed grain dryer rate is much too high", and that it is "too high in comparison to existing rates, too high in relation to alternative rate options, too high in relation to cost of service, or too high in relation to competition . . ." (BEAR Ex. 2, p. 2) In terms of what she meant by "too high relative to the cost of service", Ms. Smith did not address the cost method Mr. Jones proposed to determine SC 66 Facility Charges. Instead, she first continued to debate the Company's original method. (See BEAR Ex. 2, p. 9) She then attempted to assert that AmerenIP used incorrect meter costs in the development of the SC 66 Facilities Charges provided in Mr. Jones' rebuttal testimony. Notably, Ms. Smith did not object to the cost method employed by Mr. Jones or his underlying analyses.

In response to Ms. Smith, AmerenIP witness Jones, in his surrebuttal testimony, explained that Ms. Smith's contention about differing meter cost values is a distinction without a difference. When the meter cost values in BEAR Exhibit LS-7 are substituted for the previously-used meter cost values found on page 1 of IP Exhibit 7.21, the impact on the proposed customer cost for serving small, medium and large size customers is relatively minor. Certainly, as Mr. Jones stated, the correct meter cost should be used to develop the cost basis for the rates and that is what he has used, which is undisputed. (IP Ex. 7.30, pp. 2-3)

Ms. Smith also contended that what she perceived to be the high SC 66 rates would result in grain drying customers switching to propane. First, she argued that switching to propane as a competitive alternative was identified as a concern in IP's last gas rate case, in 1993. (BEAR Ex. 2, pp. 2-4) She neglected to point out that prior to that last gas rate case, grain drying customers took service under SC 65, and that SC 67, a special tariff for grain dryers, was proposed and implemented to alleviate that concern. (IP Ex. 7.30, pp. 3-4) Mr. Jones explained that grain drying customers switching to propane was unlikely because natural gas service under proposed SC 66 is competitively superior to propane for nearly all of AmerenIP's existing SC 67 (grain drying) customers. Only a handful of these customers, with little or no gas use, would be better off on propane service, assuming that propane service would not entail a fixed tank rental charge. Mr.

Jones used gas costs from the September and October 2003 time periods in this comparison. (IP Ex. 7.19, pp. 24-25; IP Ex. 7.28) In response, Ms. Smith took issue with the period of time used by Mr. Jones in his natural gas versus propane service cost competitive analysis (BEAR Ex. 2, p. 4), but she provided no empirical analysis of her own. Mr. Jones, however, explained that the commodity costs for propane and natural gas tend to be highly correlated and provided cost data for 2002, 2003 and year to date 2004 to demonstrate this. (IP Ex. 7.30, p. 4; IP Ex. 7.32)

Ms. Smith also asserted that a customer taking service under SC 66 may pay more than a customer taking service under SC 67 or SC 68. (BEAR Ex. 2, pp. 5-6) However, she ignored that SC 66 is an optional service. If the grain drying or asphalt customer's belief is that there are other rates more cost beneficial (e.g., SC 63, SC 64 or SC 65), the customer should take the other tariff. Further, seemingly lost in Ms. Smith's "analysis" is the fact that a customer taking service under SC 66 will be assessed only the Rider B Commodity Gas Charge, and not the Rider B Demand Gas Charge (unless the customer uses gas on a day when the temperature is below the temperature threshold). Customers on present SC 67, for example, are charged the higher Rider A Gas Charge (which incorporates both pipeline demand-related and commodity-related gas costs). The Rider A Gas Charge is usually about $.05 to $.06 per therm higher than the Rider B Commodity Gas Charge. For Ms. Smith to ignore the applicability of Rider A and Rider B in her comparison of SC 66 to other tariffs is to consider the rate impact of proposed SC 66 in a vacuum. (IP Ex. 7.30, pp. 5-6) Again, no mention of this distinction is made by Ms. Smith in her rebuttal testimony even though it had been addressed by the Company in its direct case.

Finally, Ms. Smith argued that AmerenIP's rates for grain dryers should be like those of AmerenCIPS and AmerenCILCO. She noted that the distribution charges in the AmerenCIPS and AmerenCILCO seasonal rates are about one-half the rates applied to non-seasonal customers.

(BEAR Ex. 2, p. 5) However, whatever the applicable distribution rates are for AmerenCIPS and AmerenCILCO, they are based on those utilities' respective costs of service, as should be the case for IP's rates. Ms. Smith did not explain how the AmerenCIPS and AmerenCILCO cost of service studies should morph into an AmerenIP cost of service study. Further, in making this comparison, Ms. Smith continued to ignore the full and complete impact of SC 66 on customers' *gas costs* as well as their distribution costs (as described above). IP witness Mr. Jones explained the delivery charges associated with SC 63, SC 64 and SC 65, and concluded that the SC 66 delivery charge offers a substantial discount over these other applicable firm service rates. (IP Ex. 7.30, pp. 7-8)

In summary, the concerns expressed by BEAR witness Smith with respect to proposed SC 66 should be rejected. Indeed, as discussed in this Section and in Section III.B, IP has made significant modifications to SC 66 as originally proposed, including developing a larger menu of Facilities Charges to be more closely tailored to individual customer characteristics, and proposing to lower the temperature threshold (i.e., the temperature below which an SC 66 customer will be assessed Demand Charges if it consumes gas) from 32 degrees F. to 25 degrees F. Proposed SC 66, as modified by AmerenIP during the course of this case, should be approved.[71]

B. <u>Transportation Tariffs - Service Classification 76 and Rider OT</u>

1. <u>Daily Balancing and Cashout</u>

AmerenIP is proposing to implement daily balancing with daily cash-out provisions for SC 76 customers. Mr. Blackburn explained that the proposed balancing provisions under SC 76 would require the customer to nominate the volume of gas to be delivered to an interconnection point, which nomination is confirmed by the customer's final pipeline transporter. This nominated

[71] AmerenIP will not implement SC 66 until AmerenIP is migrated to the other Ameren utilities' customer service system. Until that time, SC 67 and SC 68 will remain in effect. (IP Ex. 8.6, pp. 28-31)

volume is deemed to be delivered to AmerenIP's gas system, regardless of the customer's actual use. For each day, actual deliveries to the customer will be compared to the customer's nomination. The resulting imbalance will be used to calculate a daily cash-out charge. The daily cash-out charge will be based upon the customer's nomination and the percentage deviation of the customer's actual use from its nomination. The Chicago citygate index price will be used in calculating the cashout amount. The cashout amount would vary based on the extent of the over- or under-delivery. (IP Ex. 8.1, pp. 6-7)

AmerenIP witness Mr. Blackburn testified that the daily balancing and cashout provisions were needed in order to ensure appropriate flexibility to AmerenIP for the benefit of its sales customers with regard to the use of Company storage facilities. Otherwise, SC 76 customers are effectively able to use storage throughout the month, even though their rates do not incorporate any allocation of storage costs. (IP Ex. 8.1, pp. 8-9)

Staff witness Charles Iannello testified in support of implementing daily balancing and cashout provisions for SC 76 customers, conditioned upon adoption of Staff's proposed daily cashout schedule, the implementation of a group balancing service by IP, and implementation of steps whereby IP would make daily usage data available to customers on a more timely basis. (Staff Ex. 8.0, p. 11) Mr. Iannello agreed that AmerenIP had justified the need to change from a monthly cashout procedure and that it was appropriate to design tariffs to ensure against gaming by customers in the use of balancing and cashout provisions. He explained that under IP's current SC 76, customers carry their imbalances from day to day and rectify those imbalances by adjusting deliveries during the course of the month or cashing out imbalances at the end of the month. By observing the market prices, customers can manage their imbalances in such a way as to benefit from the current design of SC 76; SC 76 customers may purposely over- or under-deliver in order to exploit differences between the expected cashout price and the prevailing market price of gas. SC 76 customers may also systematically under-deliver on days when market prices are relatively high and over-deliver on days when market prices are relatively low. (Staff Ex. 8.0, p. 12)

AmerenIP agreed to the conditions that Staff witness Iannello proposed for the implementation of daily balancing and cashout. Specifically, AmerenIP agreed to the daily imbalance cashout schedule proposed in Mr. Iannello's direct testimony (Staff Ex. 8.0, p. 39), except that AmerenIP proposed that the customer's net accumulated daily imbalances within a 20% deadband would be cashed out at the end of the billing period (i.e., monthly). As discussed in greater detail in Section IV.B.2 below, AmerenIP also agreed to the implementation of a group balancing service. Further, as discussed in Section IV.B.3 below, AmerenIP, in direct response to Staff witness Iannello, agreed to install advanced metering and communication equipment at SC 76 customers' premises to record daily usage and to make the daily usage information available electronically to the customer. (IP Ex. 8.6, pp. 2-3)

IIEC initially took issue with AmerenIP's proposed daily imbalance provisions. IIEC witness Mallinckrodt testified that certain of the provisions were "unreasonably stringent", in part because AmerenIP was not providing customers with usage information that would allow them to react in a timely manner. (IIEC Ex. 1, p. 3) Mr. Mallinckrodt also took issue with the 10% daily balancing provision initially proposed by AmerenIP. However, AmerenIP has agreed to Staff's daily imbalance cashout schedule which affords transportation customers greater flexibility than did IP's original proposal, including adopting a 20% deadband within which no daily cashout occurs. In addition, AmerenIP has agreed to the installation of advanced metering equipment and communications equipment that would permit customers to access daily usage information on a timely basis (within four to six hours after the end of the 24-hour "gas day", see Tr. 41-42). By the end of the case, the specific steps that IIEC believed should be implemented in order to make daily balancing and cash out acceptable had been agreed to by AmerenIP, as IIEC witness Mallinckrodt acknowledged. (See Tr. 225-232)

The other assertion made by IIEC in opposing daily balancing was essentially one of "no harm, no foul". The reality, though, is that transportation customers can and will game the nomination and scheduling of their gas supply if subjected only to monthly balancing provisions. IIEC witness Mallinckrodt acknowledged that his clients are large consumers of natural gas who can be considered sophisticated gas purchasers.[72] (Tr. 223-225) Presumably, these sophisticated gas purchasers are aware (either through their own gas procurement staffs or through marketers or other advisors they may retain) of the daily market price of gas in relation to the current terms and conditions under the SC 76 tariff and will, to the extent possible, manage their gas supply portfolios in a manner that is most financially and operationally advantageous to them. To the extent this occurs, AmerenIP and its sales customers can and do bear the financial and operational brunt of these large industrial customers' actions. In fact, the net daily imbalance of all SC 76 customers is greater than 10% about half the time and is greater than 25% every tenth day. (IP Ex. 8.6, p. 16)

Accordingly, the Commission should approve AmerenIP's proposed daily balancing and cashout provisions (as revised in rebuttal testimony) for SC 76, which incorporate the recommendations of Staff witness Iannello. The new daily balancing and cashout provisions will not go into effect, however, until (i) AmerenIP is prepared to implement its group balancing service (discussed immediately below) and (ii) AmerenIP has installed the advanced metering and telecommunications equipment for SC 76 customers, to enable those customers to obtain their daily usage information within four to six hours after the end of the gas day. None of these provisions

[72]The IIEC companies in this case are well-known Illinois industrialists: Archer-Daniels-Midland Company, A.E. Staley Manufacturing Company, Caterpillar, Inc. and TeePak, LLC.

will be implemented until the first day of the month in which AmerenIP is migrated from its current customer accounting and billing system to the customer service system used by the other Ameren utilities. (IP Ex. 16.1, pp. 2-3; IP Ex. 8.6, pp. 29-31)

2. Group Balancing Tariff

As described in greater detail in Section III.B.1 above, AmerenIP seeks to implement daily balancing and daily cashout for transportation customers. After IP made modifications to its original proposal, Staff and other interested parties were amenable to this proposal conditioned upon AmerenIP implementing a group balancing service for SC 76 and Rider OT customers, among other conditions. In response to other parties' initial concerns about daily balancing and cashout, AmerenIP committed to implement a group balancing tariff (sometimes referred to in the case as a supplier aggregation tariff). A group balancing service would allow transportation customers to aggregate their loads and among other benefits, this aggregation would assist the customers in minimizing and avoiding both daily and monthly imbalances and associated cashout requirements. AmerenIP is willing to implement a group balancing service for AmerenIP's SC 76 and Rider OT customers similar to AmerenCIPS' Rider G, Group Balancing Service, if AmerenIP's daily balancing and daily cashout proposals (as IP modified those proposals during the course of the case) are accepted. (IP Ex. 16.1, p. 2)

AmerenIP proposed that implementation of the group balancing service will occur on the first day of the month in which AmerenIP's current billing system is converted to the customer service system used by the other Ameren utilities. The current best estimate as to when AmerenIP will be migrated to the Ameren customer service system is October 2005. (IP Ex. 8.14, p. 10) This will allow time for AmerenIP to modify the programming, contracts, forms and procedures developed for AmerenCIPS' Rider G, in conjunction with AmerenIP's SC 76 and Rider OT transportation rates. Additionally, the daily balancing and cashout provisions would not go into effect until the group balancing service goes into effect. (IP Ex. 16.1, pp. 2-3)

Constellation NewEnergy, LLC – Gas Division ("CNE Gas") recommended that the Commission require AmerenIP to implement the group balancing service no later than September 1, 2005, and to file its proposed tariff no later than 60 days prior to that date. (CNE Gas Ex. 3, pp. 4-5) AmerenIP agrees to post the tariff 45 days prior to the anticipated effective date; however, as explained by AmerenIP witness Dottie Anderson, the current IP billing system is not programmed to handle the group balancing service. It would be a waste of time and resources to modify the current legacy IP billing system to accommodate the group balancing service when within only a few more months, at most, AmerenIP will be converted to the Ameren billing system. (IP Ex. 16.3, pp. 4-5; IP Ex. 8.6, pp. 30-31; IP Ex. 8.14, p. 5) Staff expressed no objection to AmerenIP's proposal to implement the group balancing tariff and the daily balancing and cashout provisions in connection with the conversion of AmerenIP to the Ameren customer service system.

3. Provision of Daily Usage Information and Advanced Metering and Telecommunications Equipment

a. Applicability of Requirement for Equipment – Mandatory versus Optional

In conjunction with adoption of the daily imbalance and cashout provisions, Staff witness Iannello recommended that AmerenIP make advanced metering and communications equipment available as an option to SC 65, SC 66 and Rider OT customers (as well as installing it for all SC 76 customers). In the Tariff Stipulation, Staff and AmerenIP stipulated that this equipment will be offered on an optional basis to SC 65, SC 66 and Rider OT customers and that AmerenIP can charge an exit fee to customers who elect this service but then terminate it before a specified period of time. (The development of the exit fee is discussed in Section IV.B.3.c, below.) IP will not be required to provide daily interval usage information to customers that do not elect this optional service. (Tariff Stipulation, par. I.2)

In addition, customers electing this optional service (as well as SC 76 customers) will be required to provide a dedicated phone line to the meter at the customer's expense. Other SC 65, SC 66 and Rider OT customers who do not elect this service will be required to provide a non-dedicated commercial phone line. (Tariff Stipulation, par. I.2 and I.4) Specifically, AmerenIP and Staff stipulated to the following language for Section 7(h) of AmerenIP's Standard Terms and Conditions:

> 7(h) Prior to providing service, Utility shall install electronic metering equipment in each meter through which Customer will be taking service under SC 65, SC 66, SC 76 or Rider OT. If sufficient metering and communications facilities already exist, at Utility's sole discretion, the requirement for installation of additional metering equipment may be waived. At Utility's sole discretion, Utility may require installation of remote interrogation equipment on Customer's electronic metering equipment. All Customers taking service under SC 65, SC 66, SC 76 or Rider OT shall provide access to a 120 volt AC electric power source and to a commercial telephone line for each meter, at Customer's expense. The commercial telephone line provided by those Customers taking service under SC 76 shall be dedicated for Utility's use. The commercial telephone line provided by Customers taking service under SC 65, SC 66 or Rider OT that elect online access to daily usage data shall also be dedicated for Utility's use. (Tariff Stipulation, par. I.5)

b. Development of Charges for Electronic Metering Equipment and for Advanced Metering and Telecommunications Equipment

AmerenIP witness Althoff provided cost information for the equipment needed to be installed in order for customers to have access to usage information on a daily basis. There are two components to the charges for this equipment. The first component would recover the cost of the electronic metering equipment necessary to record the customer's daily demands. The second component would recover the cost of the communications equipment needed to allow AmerenIP to remotely access information contained within the customer's meter.

As updated based on the final, stipulated cost of capital in this case, the monthly cost for the electronic metering index is $16.59 and the monthly cost for the communication equipment is $21.19. The total monthly cost for both is $37.78. (Tariff Stipulation, App. A) Based on these monthly costs, the stipulated monthly charges are $16.50 for the electronic metering index and $21.25 for the communication equipment. (Tariff Stipulation, par. I.3; see IP Ex. 7.30, p. 15)

c. <u>Exit Fee</u>

If a SC 65, SC 66 or Rider OT customer chooses to take optional metering and communications service but then later elects to terminate that service, AmerenIP will be exposed to non-recovery of the installed costs of this equipment. As Mr. Jones explained, "this kind of flexibility left unchecked is potentially expensive (unrecovered revenues) to the Company and ultimately expensive to the Company's other customers (increased rates)." (IP Ex. 7.30, p. 15) Mr. Jones explained that to address this problem, either the SC 65, SC 66 and Rider OT customers could pay an upfront fixed fee for the service and forgo the incremental monthly meter communications fee, or the customers could be charged an exit fee if they elect to leave the service within a specified time period following the initial equipment installation date. The amount of the exit fee would be determined by the following formula: Exit Fee equals (Required number of months minus number of previous monthly payments) times monthly fee. (IP Ex. 7.30, p. 16)

In the Tariff Stipulation, AmerenIP and Staff stipulated that AmerenIP would be allowed to charge the exit fee to customers that elect the optional electronic metering and communications equipment but then terminate this service in less than six years (72 months). The customer's exit fee will be calculated as follows: Exit Fee equals (72 months minus number of previous monthly payments) times $21.25. (Tariff Stipulation, par. I.4)

4. IIEC's Proposed Storage Service

Dr. Rosenberg on behalf of IIEC testified that AmerenIP should be required to offer an optional storage service for transportation customers. Under his proposal a customer would elect a Balancing Maximum Quantity ("BMQ") in therms per day and could nominate up to 150% of its Maximum Daily Quantity ("MDQ") plus 50% of the BMQ (meaning now 200% of the MDQ. (Tr. 206). The customer would be able to meter up to 120% of its nomination (meaning 240% of the MDQ (Tr. 206)) plus 75% of its BMQ. On critical days, the BMQ would zero. The customer's cumulative storage bank would not be allowed to fall below zero. On October 31 of each year, the customer's cumulative bank would be required to be at or below 500% of its BMQ; any excess would be cashed out. Dr. Rosenberg proposed a monthly charge for this service of $.05 per therm of BMQ. (IIEC Ex. 2, pp. 13-14) The IIEC proposal is deficient in a number of respects, is results driven in its entirety, and should be rejected by the Commission.

Dr. Rosenberg claimed that the premise for his storage service proposal was the mitigation of potential balancing costs to the SC 76 customers. However, as discussed in Sections IV.B.1 and 2 above, AmerenIP has agreed to many rate design and other changes that will provide additional flexibility regarding balancing for SC 76 customers (and other customers as well). AmerenIP has agreed to implement a group balancing service and to modify its original daily balancing and cashout proposal so as to provide for an initial 20% deadband within which there will be no daily cashout payments.[73] Further, AmerenIP will make available to SC 76 customers daily usage information that will assist customers in remaining in balance.

[73]Under the group balancing tariff, the aggregate daily imbalance of all the customers in the group will determine whether the customers are subject to a daily cashout requirement (i.e. whether as a group the customers are within or without the 20% deadband). (See Tr. 230-231)

Moreover, there is already storage service available for Dr. Rosenberg's clientele – they simply have to pay for the service. Customers can have access to storage service by taking a firm supply rate and transportation service under Rider OT. (IP Ex. 8.14, p. 9) Additionally, retail customers can obtain storage services from interstate pipelines and third party providers. (Tr. 78)

IIEC's proposal is clearly results driven, as AmerenIP witness Blackburn demonstrated in his rebuttal testimony. Mr. Blackburn put forth a hypothetical example that showed how a transportation customer could take advantage of IIEC's proposed storage service if IP were required to offer it. Even though the hypothetical customer would receive basically the same level of service as under IP's proposals, the customer would pay far less ($4,846 per month as compared to $3,592 per month) under Dr. Rosenberg's proposal as a result of taking advantage of the IIEC-designed storage service. (See IP Ex. 8.6, pp. 23-24) Notably, Dr. Rosenberg did not attempt to refute Mr. Blackburn's hypothetical in his own rebuttal testimony.

The deficiencies and faulty assumptions in IIEC's storage service proposal are numerous. The fact that the customer's BMQ would be zero on critical days is a nearly irrelevant consideration insofar as many of the largest SC 76 customers' peak day loads occur during times when critical days are not likely to occur. (IP Ex. 8.6, p. 24) In effect, offering that the BMQ is zero on critical days, as Dr. Rosenberg did, is near purposeless.

Although Dr. Rosenberg asserted that his proposed optional storage service is a means to enable transportation customers to mitigate against potential imbalances, under Dr. Rosenberg's proposal the customer may nominate injections into the optional storage service and, therefore, there would be no mitigation activity. (*Id.*, pp. 24-25) Dr. Rosenberg's backup plan, that a customer should be able to inject at least 22% of its BMQ into storage is also flawed. In developing this proposal, Dr. Rosenberg employed the incorrect peak day allocator, as he excluded SC 76 and SC

90 volumes. Then without any basis in fact, Dr. Rosenberg suggested that "diversity" allows for the 22% BMQ to be inflated to 50%. He cannot say, however, that on each and every day there will be diversity, or even enough diversity on the system that would allow for his arbitrary inflation. (IP Ex.8.6, pp. 25-26). Also, Dr. Rosenberg's cross examination is most revealing. In effect, he sought to change the terms of his proposal. (Tr. 206-207)

In the end, there has been no demonstrated need for the service, that is, no one is claiming they cannot do business unless the optional storage service is provided. And again, Dr. Rosenberg conveniently ignores Rider OT, the reason being, he wants more for less cost. Regardless of his motivation, Dr. Rosenberg's proposal is not well thought out. He offered qualifiers while on the stand, and as Mr. Blackburn explained, to do what Dr. Rosenberg wants has an impact on other rates and rate design issues, none of which have been tested in this case. (IP Ex. 8.14, p. 10)

IIEC's proposal to require AmerenIP to offer an optional storage service to SC 76 customers is ill-considered, poorly developed and supported, and should be rejected by the Commission. Further, in case there was any concern that SC 76 customers needed additional flexibility to mitigate potential imbalances under the daily balancing provisions IP originally proposed in this case, those concerns should have largely dissipated as a result of AmerenIP's agreement to adopt Staff witness Iannello's modifications, including the expanded daily balancing tiers, the 20% deadband and the implementation of a group balancing service.

5. <u>Recovery of Transportation Administration Costs</u>

Illinois Power's present transportation tariffs, SC 76 and Rider OT, contain an Administrative Charge intended to recover the Company's additional administrative costs associated with handling transportation accounts. IP proposed to continue the Administrative Charge for transportation customers in the tariffs approved in this case. (IP Ex. 7.10, pp. 21-22, 22-23) However, Staff witness Iannello proposed that the Administrative Charge for transportation customers be eliminated and that these costs instead be recovered through the Facilities Charges applicable to all customers under SC 63, SC 64, SC 65 and SC 76 (i.e., customers eligible to transport gas). Mr. Iannello's rationale was that imposition of a separate Administrative Charge to transportation customers only could present a disincentive to customers electing to purchase and transport their own gas; and that IP's administrative costs to serve transportation customers are largely fixed and do not increase with the addition of each new transportation customer. (Staff Ex. 8.0, pp. 33-37) Although Illinois Power does not necessarily agree with Mr. Iannello's concern, IP agreed to Mr. Iannello's proposal. (IP Ex. 7.19, p. 17) Accordingly, the Administrative Charge has been eliminated from proposed SC 76 and Rider OT, and the Facilities Charges in SC 63, SC 64, SC 65 and SC 76 (as included in IP Appendix A and IP Appendix B included with this Brief) have been reset to reflect that the cost associated with administration of transportation tariffs are to be borne by all non-residential customers. (*Id.*)

6. <u>Critical Day Imbalance Charge</u>

Illinois Power proposed a Critical Day Imbalance Charge ("CDIC") for SC 76. Under the CDIC as originally proposed by IP, on a critical day called by IP on which a customer's imbalance differs by more than the greater of 10% of the customer's nomination or 1,000 therms and contributes to imbalance charges imposed on IP (as the Point Operator and balancing agent) by an interstate pipeline (i.e., the customer's imbalance is in the same direction as IP's imbalance on the pipeline), the customer's imbalance will be subject to an additional CDIC.[74] The CDIC

[74]The pipeline penalties or fees could be the result of (1) transporting customers taking more or less gas than they deliver to IP's system, (2) IP taking more or less gas than it delivers to its

would be calculated as the aggregate of pipeline penalties or fees incurred by IP for the critical day divided by the aggregate therms of imbalance created by SC 76 customers and Illinois Power that contributed to the penalties and fees. The CDIC would be applied to those transporting customers contributing to the penalties or fees, and would be assessed on the basis of the customer's therms of Critical Day Imbalance, which is that imbalance in excess of the greater of 10% of the customer's nomination and 1,000 therms, that contributed to the pipeline penalties or fees. (IP Ex. 8.1, pp. 8, 9-10)

Staff witness Iannello expressed one concern about the proposed CDIC, namely, that it treated transportation customers individually rather than as a group for purposes of assessing the CDIC. He recommended that, instead, the imbalances of all transportation customers as a group be considered in applying the CDIC, thereby allowing the imbalances of transportation customers in the direction of the pipeline imbalance to be offset by any transportation customer imbalances in the opposite direction. (Staff Ex. 8.0, pp. 31-33) He also noted that where IP calls a critical day for only a portion of its service area, then the subset of SC 76 customers located in the area for which the critical day was declared should be treated as a group for purposes of assessing the CDIC. (Staff Ex. 18.0, p. 13)

AmerenIP and Staff have stipulated to adopt Mr. Iannello's above-described modifications to the Company's CDIC proposal. (Tariff Stipulation, par. I.1)

7. Other Changes to Rider OT

In its tariff filing, Illinois Power proposed the following changes to Rider OT, Optional Transportation of Customer-Supplied Gas with Firm Utility Gas Supply Backup:

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system for its bundled supply customers, or (3) IP taking more gas than that to which it is contractually entitled. (IP Ex. 8.1, p. 9)

- Eliminate the current practice of cashing out the customer's storage bank balance in October of each year;

- Change the price on which billing period cashouts are based to the Chicago citygate index price; and

- Provide specific intra-gas day nomination rights for Rider OT customers. (IP Ex. 8.1, p. 16)

In addition, in Rider OT IP is formalizing its current practice of allowing customers to nominate only on those pipelines that can provide gas to the customer. This access can change over time due to physical changes on the system, contractual changes with the pipelines and seasonal operational constraints. AmerenIP will be responsible for updating this information and making it available to transporting customers. (*Id.*) There was no objection to any of these changes.

Rider OT is an optional service that can only be taken in conjunction with a firm supply tariff (SC 63, SC 64, SC 65 or SC 66), and Rider OT customers have access to gas supply from AmerenIP pursuant to its PGA tariffs, Rider A and Rider B. Therefore Rider OT customers receive the benefits of the peaking and price diversity functions of Company storage and, accordingly, storage costs are allocated to these customers in the cost of service analysis. (*Id.*)

C. Other Changes to Bundled Gas Tariffs (Service Classifications 51, 63, 64 and 65)

In its tariff filing, Illinois Power proposed to change the term "Commodity Charge" to "Delivery Charge" in SC 51, SC 63, SC 64 and SC 65. (IP Ex. 8.1, p. 3) There was no objection to this change. All other issues relating to changes to AmerenIP's bundled gas service tariffs proposed in this case are addressed in other sections of this Brief.

D. Other Changes to AmerenIP's Standard Terms and Conditions and Rules, Regulations and Conditions Applying to Gas Service

In addition to the proposed changes to its individual service classifications and riders discussed elsewhere in this brief, Illinois Power's proposed tariffs reflect a number of changes in its Standard Terms and Conditions and its Rules, Regulations and Conditions Applying to Gas Service ("Rules")[75]. The proposed changes to the Standard Terms and Conditions include the following (IP Ex. 8.1, pp. 17-18):

- Consolidation of the provisions regarding resale and redistribution;
- Elimination of the Energy Audit Charge and Arrearage Pilot Program (IP no longer provides energy audits to customers, and the Arrearage Pilot Program expired on April 30, 2000 (IP Ex. 8.1, p. 19));
- Elimination of the provision requiring a minimum initial required MDQ for non-residential customers;
- Clarification that the absence of a nomination by a transportation customer will be treated as a nomination of zero;
- Removal of common definitions and terms and conditions from the SC 76 and Rider OT tariffs and placement of these common terms and definitions in the Standard Terms and Conditions; and
- Addition of several definitions and minor language changes for consistency with IP's electric utility Standard Terms and Conditions (for example, Sections 2 (Modification of Schedule of Rates and Contracts), 3 (Terms of Payment) and 4 (Additional Charges)).

With respect to the consolidation of the provisions regarding resale and redistribution, the consolidated provision (Section 1 of the Standard Terms and Conditions) incorporates language from the current Standard Terms and Conditions, Rules and IP's Gas Operating Procedures, and is intended to provide a more complete description of those situations that require separate metering and billing. The proposed provision does not represent a change from IP's current practices. Generally, unless heat or hot water is provided to tenants of a building through a common system without incremental charges for such service, or unless units meet certain other criteria detailed in this tariff section, separate metering and billing is required. (IP Ex.8.1, p. 18)

[75]The proposed gas Standard Terms and Conditions are included in IP Exhibit 8.2 and the proposed gas Rules are included in IP Exhibit 8.3, both sponsored by IP witness Blackburn.

The provision requiring a minimum required initial MDQ is being eliminated in order to allow the customer to establish its initial MDQ at a level that reflects the customer's expected operations rather than past operations. The excess MDQ charges in IP's tariffs provide sufficient incentive for customers to set their MDQs at appropriate levels. (IP Ex. 8.1, p. 19)

The proposed changes to IP's gas Rules include the following (IP Ex. 8.1, pp. 19-20):

- Removal of definition from the Rules and placement of the definitions into the Standard Terms and Conditions, so that definitions are found in one place;
- Removal of provisions concerning resale and redistribution and consolidation of provisions on this topic into the Standard Terms and Conditions, as discussed above;
- Clarification of IP's right to relocate gas facilities at the customer's expense if the customer's premises, operations or gas utilization are dangerous;
- Clarification that customers will bear the cost of changes in gas facilities that they initiate regardless of potential revenue impacts;
- Clarification that base rate revenue is the basis for the revenue allowance calculation for determining the length of free gas main extensions;
- Clarification as to what constitutes dangerous conditions that would allow IP to deny or terminate service;
- Clarification that additional costs incurred in disconnecting or reconnecting service other than at the meter may be borne by the customer; and
- Minor language changes to improve clarity.

With respect to the clarifications in the gas Rules that a customer bears the cost of relocating facilities due to an unsafe condition if the customer is responsible for the unsafe condition, that the customers are responsible for the costs of changes to facilities that they initiate, and that a customer may bear the additional costs incurred by IP in disconnecting or reconnecting service other than at the meter, these provisions are intended to follow the principle that a customer that causes such costs should be responsible for paying those costs instead of the costs being spread across all customers. (IP Ex. 8.1, p. 20) With respect to the clarification that the customer's base rate revenue is the basis for the revenue allowance for determining the length of the free gas main extension provided to the customer, IP receives no profit from gas sales, only dollar-for-dollar cost recovery; therefore, it would be inappropriate to incorporate the cost of gas consumed by the customer into the revenue allowance for determining the length of the free gas main extension. (*Id.*, pp. 20-21)

Other than provisions that are specifically discussed elsewhere in this Brief, no party took issue with any of the proposed changes to IP's Standard Terms and Conditions or to its Rules. Accordingly, the proposed Standard Terms and Conditions and Rules (except to the extent modified during the course of this case as discussed elsewhere in this Brief) should be approved.

E. Treatment of Past-Due Payments

As permitted by 83 Ill. Admin. Code 280.90(a), Illinois Power treats a customer payment as past due if the payment is received more than two days after the due date printed on the customer's bill. CNE Gas witness Juliana Claussen testified that IP should elect the option of treating a payment as past due if the payment is postmarked after the due date printed on the bill. (CNE-Gas Ex. 1.0, p. 9)

Illinois Power does not accept this proposal. Code Part 280.90(a) identifies the two options referred to by Ms. Claussen by which a utility may determine if payments are past due, and Code Part 280.90(b) states, "Each utility shall choose one of the above methods for determining when a bill is past due and shall apply this method to all customers." IP has elected to use the method that requires mailed payments to be received by IP within two days following the due date in order to be considered on time (not past due). Code Part 280.90(b) allows IP to elect to use this option (and does not authorize the Commission to direct a utility to use the other option). Further, for IP to change to the "postmark" method for all customers (as it would be required to do by Part 280.90(b)) would result in significant added administrative expense and costs for changes and reprogramming to IP's billing systems. Additionally, the "postmark" method would be less cost-effective, because IP would have to document and/or store the postmarks on hundreds of thousands of envelopes sent to the Company each month. Finally, use of the "postmark" method would likely extend the date on which many customers send payments to IP, thereby slowing IP's cash flow and increasing its cash working capital requirements, which would increase the Company's revenue requirement and be paid for by all customers. (IP Ex. 8.6, p. 10)

Customers who are concerned about possible mail delays in the receipt of their payments by IP can avoid this risk by using other payment options. Any IP customer may elect to pay bills via an electronic funds transfer, to pay electronically via the internet, to pay from a financial account or by credit card over the phone, or to pay in person at a payment center. (*Id.*, p. 11) These options allow the customer to pay the bill on the due date without payment being past due.

Ms. Claussen of CNE-Gas described the "postmark" option as "customer friendly" (CNE-Gas Ex. 1.0, p. 9) but what she may have really meant is "marketer friendly". Many marketers receive and pay their customers' distribution service bills and then invoice their customers on a single-bill basis for pipeline services, distribution services and the cost of gas obtained and supplied by the marketer. In reality, a switch to the "postmark" method would allow gas marketers to mail payments to IP on the due date and enjoy several additional days of float and interest cost savings, at the expense of Illinois Power and, ultimately, its other customers.

When a payment is past due, Illinois Power assesses a 1.5% late payment charge on the past due amount. Ms. Claussen testified that the late charge should be prorated based on the number of days (out of 30 in the month) that the payment is received past the due date. (CNE-Gas Ex. 1.0, p. 9) This proposal should also be rejected. Among other things, use of the approach she suggested would reduce the amount of revenues IP receives from forfeited discounts. Since forfeited discount revenues are included in miscellaneous revenues that are deducted from the overall revenue requirement to determine the net revenue requirement that must be recovered from customers through base rate charges, Ms. Claussen's proposed approach would require an increase in base gas rates. (IP Ex. 8.6, pp. 11-12) Further, Illinois Power's practice with respect to application of the 1.5% late payment charge is the same as the practices of all the other major Illinois electric and gas utilities including Commonwealth Edison, AmerenCIPS, AmerenCILCO, Peoples Energy and Nicor Gas. (*Id.*, p. 11)

F. <u>Lost and Unaccounted for Factor (Factor U)</u>

Factor U is AmerenIP's unaccounted for gas adjustment charge. IIEC witness John Mallinckrodt, in his direct testimony filed in November 2004, complained that the Factor U charge for 2004 was inappropriate, on the grounds that it was large in comparison to prior years. Mr. Mallinckrodt recommended that the Factor U charge be reduced from its current (2004) level of about 2.6%, to 2.2%. He proposed a three-year averaging of the Factor U charge. (IIEC Ex. 1 pp. 15-16)

It is apparent Mr. Mallinckrodt fails to understand the nature and application of a Factor U charge. Notably, he offered no empirical evidence as to why it was (in his view) too high or too low, or why any averaging was appropriate given the nature of the charge. The Factor U charge is a pass through on which AmerenIP makes no profit, as Staff confirmed. (IP Ex. 8.6, p.

19; Staff Ex. 17.0R, p. 4) In any event, AmerenIP calculated the new annual Factor U charge to be effective beginning January 1, 2005, and it will be 1.711%, lower than what it was for 2004, and even lower than the 3-year averaging proposal suggested by Mr. Mallinckrodt. (*Id.*) Upon discovering the new Factor U charge was less than what his three-year average would have produced, Mr. Mallinckrodt readily agreed to accept AmerenIP's Factor U for 2005. (IIEC Ex. 1.1, p. 8)

In his rebuttal testimony, Mr. Mallinckrodt also suggested that a procedure should be put in place in the future to review the Factor U proposed each year. (IIEC Ex. 1.1, p. 8) Apparently, Mr. Mallinckrodt is unfamiliar with the applicable gas utility regulatory practices in Illinois. As explained by Mr. Blackburn, the historical loss factors are provided to the Staff each year as part of a utility's PGA reconciliation case. Thus, there is no need for a specific, separate procedure to review Factor U each year. (IP Ex. 8.14, p. 9) Further, Staff testified that IP should not make any changes in the way it calculates its Factor U. (Staff Ex. 17.0R, p. 4)

G. Definition of "Therm"

IIEC witness Mallinckrodt testified that AmerenIP's gas accounting and billing should be done on a heat content basis rather than on a volumetric basis. AmerenIP agreed with Mr. Mallinckrodt that there was a mismatch between the Chicago citygate index price (which is stated on an MMBtu (heat content) basis) that is to be used for cashout purposes and the volumes delivered to IP customers, which are measured on a volumetric basis. In order to address this inconsistency, IP agreed to convert the Chicago citygate price to a volumetric basis for cashout purposes. The conversion will be based on the Btu content of gas delivered to AmerenIP's city gate by NGPL. (IP Ex. 8.6, p. 20) Mr. Mallinckrodt indicated acceptance of this change. (IIEC Ex. 1.1, p. 8)

Notwithstanding the above-described change by IP, Mr. Mallinckrodt continued to argue that AmerenIP should change its gas accounting system to bill and handle gas on a Btu basis. (IIEC Ex. 1.1, p. 9) However, Mr. Blackburn pointed out that both AmerenCIPS and AmerenCILCO utilize a volumetric measurement basis for the therm. (IP Ex. 8.6, pp. 19-20) He also explained that the volumetric measure is used for retail customer billing because most meters at customer premises measure only volumes, not heat content. (Tr. 85)

V. CONCLUSION

The Commission should accept Illinois Power's Hillsboro base gas inventory value and include it in rate base and should find the Hillsboro Storage Field to be fully used and useful, resulting in a base rate revenue increase in this case of $14,227,000. In addition, the Commission should adopt Illinois Power's cost of service study, interclass revenue allocation, rate design and specific proposed rates and charges for the individual service classifications, in particular the interclass revenue allocation and proposed prices set forth in IP Appendix B to this Brief. Finally, the Commission should approve Illinois Power's other proposed tariff terms and conditions, including in particular those for SC 66 and SC 76, as discussed in Section IV of this Brief.

Respectfully submitted,

ILLINOIS POWER COMPANY

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